Northeast
Utilities System

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2007

OR

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

For the transition period from _____ to _____

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	02-0181050
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

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

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Northeast Utilities	Common Shares, $5.00 par value	New York Stock Exchange, Inc.

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

Registrant	Title of Each Class
The Connecticut Light and Power Company	Preferred Stock, par value $50.00 per share, issuable in series, of which the following series are outstanding:

$1.90	Series	of 1947
$2.00	Series	of 1947
$2.04	Series	of 1949
$2.20	Series	of 1949
3.90%	Series	of 1949
$2.06	Series E	of 1954
$2.09	Series F	of 1955
4.50%	Series	of 1956
4.96%	Series	of 1958
4.50%	Series	of 1963
5.28%	Series	of 1967
$3.24	Series G	of 1968
6.56%	Series	of 1968

Public Service Company of New Hampshire and Western Massachusetts Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

Yes	No
Ö	

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes	No
	Ö

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

Yes	No
Ö	

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. **[** Ö **]**

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer
Northeast Utilities	Ö		
The Connecticut Light and Power Company			Ö
Public Service Company of New Hampshire			Ö
Western Massachusetts Electric Company			Ö

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

	Yes	No
Northeast Utilities		Ö
The Connecticut Light and Power Company		Ö
Public Service Company of New Hampshire		Ö
Western Massachusetts Electric Company		Ö

The aggregate market value of **Northeast Utilities'** Common Shares, $5.00 Par Value, held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of Northeast Utilities' most recently completed second fiscal quarter (June 30, 2007) was **$4,391,733,431** based on a closing sales price of **$28.36** per share for the 154,856,609 common shares outstanding on June 30, 2007. **Northeast Utilities** holds all of the 6,035,205 shares, 301 shares, and 434,653 shares of the outstanding common stock of **The Connecticut Light and Power Company, Public Service Company of New Hampshire** and **Western Massachusetts Electric Company,** respectively.

Indicate the number of shares outstanding of each of the registrants' classes of common stock, as of the latest practicable date:

Company - Class of Stock	Outstanding at January 31, 2008
Northeast Utilities Common shares, $5.00 par value	155,153,646 shares
The Connecticut Light and Power Company Common stock, $10.00 par value	6,035,205 shares
Public Service Company of New Hampshire Common stock, $1.00 par value	301 shares
Western Massachusetts Electric Company Common stock, $25.00 par value	434,653 shares

Documents Incorporated by Reference:

Description	Part of Form 10-K into Which Document is Incorporated
Portions of Annual Reports of the following companies for the year ended December 31, 2007:	
Northeast Utilities	Part II
The Connecticut Light and Power Company	Part II
Public Service Company of New Hampshire	Part II
Western Massachusetts Electric Company	Part II
Portions of the Northeast Utilities Proxy Statement dated March 31, 2008	Part III

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found in this report:

COMPANIES

Boulos	E. S. Boulos Company
CL&P	The Connecticut Light and Power Company
Con Edison	Consolidated Edison, Inc.
CRC	CL&P Receivables Corporation
CYAPC	Connecticut Yankee Atomic Power Company
Globix	Globix Corporation
HWP	Holyoke Water Power Company
Mt. Tom	Mt. Tom generating plant
MYAPC	Maine Yankee Atomic Power Company
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company and subsidiaries
NU or the company	Northeast Utilities
NU Enterprises	NU Enterprises, Inc. is the parent company of Select Energy, Inc. (Select Energy), the E. S. Boulos Company (Boulos), Northeast Generation Services Company (NGS) and Select Energy Contracting, Inc. (SECI).
NUSCO	Northeast Utilities Service Company
Parent and other companies	Parent and other companies is comprised of NU parent, Northeast Utilities Service Company, HWP (since January 1, 2007) and other subsidiaries, including Rocky River Realty Company and the Quinnehtuk Company (both real estate subsidiaries), Mode 1 Communications, Inc. (telecommunications) and the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company), Yankee Energy Financial Services Company, and NorConn Properties, Inc.
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's regulated companies, comprised of the electric distribution and transmission segments of CL&P, PSNH, WMECO, the generation segment of PSNH, and Yankee Gas, which is a natural gas local distribution company. For further information, see Note 16, "Segment Information," to the consolidated financial statements.
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
Woods Electrical	Northeast Acquisition Company, formerly Woods Electrical Co., Inc. a portion of the business of which was sold in April of 2006 and the remainder of which was wound down in the second quarter of 2007.
WMECO	Western Massachusetts Electric Company
Woods Network	Woods Network Services, Inc.
YAEC	Yankee Atomic Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Companies	CYAPC, MYAPC and YAEC
Yankee Gas	Yankee Gas Services Company

MILLSTONE UNITS

Millstone 1	Millstone Unit No. 1, a 660 megawatt nuclear unit completed in 1970; Millstone 1 was sold in March of 2001.
Millstone 2	Millstone Unit No. 2, an 870 megawatt nuclear electric generating unit completed in 1975; Millstone 2 was sold in March of 2001.
Millstone 3	Millstone Unit No. 3, a 1,154 megawatt nuclear electric generating unit completed in 1986; Millstone 3 was sold in March of 2001.

REGULATORS

CDEP	Connecticut Department of Environmental Protection
DOE	United States Department of Energy
DPU	Massachusetts Department of Public Utilities (formerly the Massachusetts Department of Telecommunications and Energy (DTE))
DPUC	Connecticut Department of Public Utility Control
FERC	Federal Energy Regulatory Commission
NHPUC	New Hampshire Public Utilities Commission
SEC	Securities and Exchange Commission

OTHER

AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
CfD	Contract for Differences
CTA	Competitive Transition Assessment
COLA	Cost of Living Adjustment
EDIT	Excess Deferred Income Taxes
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation No.
GSC	Generation Service Charge
GWH	Gigawatt Hours
FMCC	Federally Mandated Congestion Charges
ISO-NE	New England Independent System Operator or ISO New England, Inc.
ITC	Investment Tax Credits
KWH or kWh	Kilowatt-hour
KV	Kilovolt
LNG	Liquefied Natural Gas
LNS	Local Network Service
LOC	Letter of Credit
MGP	Manufactured Gas Plant
MMCF	Million Cubic Feet
MW	Megawatts
NYMPA	New York Municipal Power Agency
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pensions
PCRBs	Pollution Control Revenue Bonds
Money Pool or Pool	Northeast Utilities Money Pool
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segments excluding the wholesale transmission segment.
Restructuring Settlement	"Agreement to Settle PSNH Restructuring"
RMR	Reliability Must Run
RNS	Regional Network Service
ROE	Return on Equity
RTO	Regional Transmission Operator
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge

SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
TCAM	Transmission Cost Adjustment Mechanism
TSO	Transitional Standard Offer
UI	The United Illuminating Company
UITC	Unamortized Investment Tax Credits
VIE	Variable Interest Entity

NORTHEAST UTILITIES
THE CONNECTICUT LIGHT AND POWER COMPANY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
WESTERN MASSACHUSETTS ELECTRIC COMPANY

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NORTHEAST UTILITIES
THE CONNECTICUT LIGHT AND POWER COMPANY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
WESTERN MASSACHUSETTS ELECTRIC COMPANY

SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

References in this Annual Report on Form 10-K to "NU," "we," "our," and "us" refer to Northeast Utilities and its consolidated subsidiaries.

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions or future events, performance or growth and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify our "forward-looking statements" through the use of words or phrases such as "believe," "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materi ally from actual results. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward-looking statements, including, but not limited to, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels and timing of capital expenditures, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports filed with the Securities and Exchange Commission (SEC) and we encourage you to consult such disclosures.

All such factors are difficult to predict, contain uncertainties which may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see Item 1A, "Risk Factors" included in this report. This Annual Report on Form 10-K also describes material contingencies and critical accounting policies and estimates in the accompanying "Management’s Discussion and Analysis" and "Notes to Consolidated Financial Statements." We encourage you to review these items.

PART I

Item 1. Business

NU, headquartered in Berlin, Connecticut, is a public utility holding company registered with the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly-owned regulated utility subsidiaries:

- The Connecticut Light and Power Company (CL&P), a regulated electric utility which serves residential, commercial and industrial customers in parts of Connecticut.
- Public Service Company of New Hampshire (PSNH), a regulated electric utility which serves residential, commercial and industrial customers in parts of New Hampshire.
- Western Massachusetts Electric Company (WMECO), a regulated electric utility which serves residential, commercial and industrial customers in parts of western Massachusetts; and
- Yankee Gas Services Company (Yankee Gas), a regulated gas utility which serves residential, commercial and industrial customers in parts of Connecticut.

We sometimes refer to CL&P, PSNH, WMECO and Yankee Gas collectively in this Annual Report on Form 10-K as the "regulated companies."

NU also owns certain unregulated businesses through its wholly-owned subsidiary, NU Enterprises, Inc. (NU Enterprises). We have exited most of these businesses. As of December 31, 2007, NUEI's remaining business consisted of (i) Select Energy Inc.'s (Select Energy) few remaining wholesale marketing contracts, and (ii) NU Enterprises' remaining energy services business.

Although NU consolidated, CL&P, PSNH and WMECO report their financial results separately, we also include information in this report on a segment, or line of business basis. The regulated companies include three business segments: the electric distribution segment (which includes PSNH's regulated generation activities), the natural gas distribution segment and the electric transmission segment. The regulated companies' segment of our business represented approximately 92.8% of our total earnings for 2007, with electric distribution (including PSNH's generation activities) representing approximately 50.1%, electric transmission representing approximately 33.5% and natural gas transmission representing approximately 9.2%. At December 31, 2007, the NU Enterprises business segment included the following legal entities: (i) Select Energy, Inc. (Select Energy), (ii) Northeast Generation Services Company (NGS), (iii) E.S. Boulos Company (Boulo s), (iv) the remaining business of Select Energy Contracting, Inc. (SECI) and (iv) NU Enterprises parent.

For information regarding each of NU's segments, see Note 16, "Segment Information," contained within NU's 2007 Annual Report to Shareholders, which is incorporated into this Annual Report on Form 10-K by reference.

REGULATED ELECTRIC DISTRIBUTION

General

CL&P, PSNH and WMECO, sometimes referred to herein as the "operating companies", are primarily engaged in the distribution of electricity in Connecticut, New Hampshire and western Massachusetts, respectively, with PSNH also participating in the regulated electric generation business. The following table shows the sources of 2007 electric franchise retail revenues for the operating companies, collectively, based on categories of customers:

Sources of Revenue	Total Operating Companies
Residential	54%
Commercial	36%
Industrial	9%
Other	1%
Total	100%

A summary of changes in the operating companies' electric kilowatt-hour (kWh) sales for the 12-month period ended December 31, 2007 as compared to December 31, 2006 on an actual and weather normalized basis is as follows:

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

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

THE CONNECTICUT LIGHT AND POWER COMPANY

Distribution

CL&P is engaged in the purchase, transmission, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2007, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 cities and towns in Connecticut. CL&P does not own any electric generation facilities.

The following table shows the sources of 2007 electric franchise retail revenues for CL&P based on categories of customers:

	CL&P
Residential	57%
Commercial	36%
Industrial	6%
Other	1%
Total	100%

Rates

CL&P is subject to regulation by the Connecticut Department of Public Utility Control (DPUC) which, among other things, has jurisdiction over rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of facilities. CL&P's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. Connecticut utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to cover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

CL&P's retail rates include a delivery service component, which includes distribution, transmission, conservation, renewables, competitive transition assessment (CTA) and other charges that are assessed on all customers. Such rates also include an electric generation service component, which includes the cost of power supply which CL&P purchases for customers that do not choose to be served by a competitive retail supplier. As a result of Connecticut legislation passed in July 2005, CL&P filed for a transmission adjustment clause on August 1, 2005. On December 20, 2005, the DPUC approved the tracking mechanism, which provides for semi-annual adjustments in January and July of each year. CL&P adjusts its retail transmission rates on a regular basis, thereby recovering all of its retail transmission expenses on a timely basis. (See "Regulated Electric Transmission" in this Annual Report on Form 10-K).

CL&P has also received regulatory orders allowing it to recover all or substantially all of its prudently incurred stranded costs, which are pre-restructuring expenditures incurred, or commitments for future expenditures made, on behalf of customers with the expectation such expenditures would continue to be recoverable in the future through rates. CL&P has financed a significant portion of its stranded costs through the issuance of rate reduction certificates secured by its right to recover stranded costs over time (securitization). CL&P recovers the costs of securitization through the CTA component of its rates. In addition to those being recovered through securitization, CL&P’s stranded costs, included, as of December 31, 2007, ongoing independent power producer costs and costs associated with the ongoing decommissioning of the Maine Yankee, Connecticut Yankee and Yankee Rowe nuclear units.

Under state law, all of CL&P's customers are entitled to choose their energy suppliers while retaining CL&P as their distribution company. CL&P purchases power for, and passes through the cost to those customers who do not choose a competitive energy supplier. Beginning January 1, 2007, this service was termed "Standard Service" for customers with less than 500 kW of demand and "Supplier of Last Resort Service" for customers with 500 kW of demand or greater. CL&P receives the cost for this service through the "Generation Service Charge" and "Bypassable Federally Mandated Congestion Charge" (FMCC) components of the customer’s bill, which is adjusted and reconciled on a semi-annual basis.

A large percentage of CL&P's customers have continued to buy their power from CL&P at Standard Service or Supplier of Last Resort rates. However, CL&P is experiencing some customer migration to competitive energy suppliers, with the movement concentrated among the larger customers. As of December 31, 2007, approximately 69,000 customers or 6% out of 1.2 million, representing approximately 33% of December 2007 load, had selected competitive energy suppliers. This customer migration is for energy supply service only so there is no impact on the delivery portion of the business or the operating income of CL&P. Energy supply service costs have been, and remain a 1-for-1 pass-through cost with no return.

On July 30, 2007, CL&P filed an application with the DPUC for an increase in its distribution rates, including an authorized regulatory return on equity (ROE) of 11% and a proposed capital budget of approximately $294 million for 2008 and $288 million for 2009. CL&P's application also contained, as required by Connecticut Public Act 07-242, "An Act Concerning Electricity and Energy Efficiencies" (Energy Efficiency Act), a proposal to implement distribution revenue decoupling from the volume of electricity sales using a revenue per customer tracking mechanism. On January 28, 2008, the DPUC issued its decision in the proceeding. The decision approved annualized increases in CL&P's distribution rates of $77.8 million for 2008 and $20.1 million for 2009, and a regulatory ROE of 9.4%, with CL&P continuing the existing earnings sharing mechanism, which provides that ratepayers and shareholders share equally in any earnings in excess of its allowed regulatory ROE. The decision also approves substantially all of CL&P's proposed capital budget. In its decision, the DPUC did not approve CL&P's proposal to achieve decoupling using a "revenue per customer" adjustment mechanism. In lieu of this proposal, the DPUC authorized compliance with the decoupling provisions of the Energy Efficiency Act via rate design that includes greater fixed recovery of distribution revenue. As compared to previous tariffs, CL&P's new distribution rates are intended to recover proportionately greater revenue through the fixed Customer and Demand charges and proportionately less distribution revenue through the per kWh charges. The new 2008 rates took effect on February 1, 2008, and the 2009 increase will take effect on February 1, 2009.

Regulatory Update

On March 30, 2007, CL&P filed a metering compliance plan with the DPUC that would meet the DPUC's objective of making time-of-use rates available to all CL&P customers. CL&P's filing discussed the technology, implementation options and costs comparing an open advanced metering infrastructure (AMI) system deployed on a geographic basis to a fixed automated metering reading (AMR) network system deployed on a usage-based priority schedule. The plan provided for full deployment by 2010. On July 2, 2007, CL&P filed a revised AMI plan consistent with the requirements of the Energy Efficiency Act, which provided for a less aggressive implementation schedule based on customer interest and allowed for future DPUC input at various milestones. CL&P requested cost recovery through its FMCC. On December 19, 2007, the DPUC issued a final decision on CL&P's compliance plan that authorized a pilot program involving the instal lation of 10,000 AMI meters and a rate design pilot to test new time-of-use and real-time rates to determine customer acceptance and load response to various pricing structures. For further information on CL&P rates, see "Regulatory Developments and Rate Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," contained in our Annual Report to Shareholders which is incorporated herein by reference.

In April 2007, pursuant to Public Act 05-01, "An Act Concerning Energy Independence" (Energy Independence Act), CL&P entered into a 15-year contract to purchase energy, capacity and renewable energy credits from a biomass energy plant beginning after completion of the plant. The contract has been approved by the DPUC and it provides for annual purchases of up to approximately 15 megawatts (MW) The DPUC has approved a sharing agreement between CL&P and The United Illuminating Company (UI) under which they will share the net costs and benefits of this contract and other contracts ultimately entered into under this program, with approximately 80% to CL&P and approximately 20% to UI, regardless of which contracts are signed by CL&P and which contracts are signed by UI. CL&P's portion of the net costs or net benefits of such contracts will be paid by or returned to CL&P's customers.

On January 30, 2008, the DPUC issued a decision approving contracts with seven more renewable energy projects of different designs totaling approximately 109 MW. The DPUC also gave contingent approval of a contract with another renewable energy project representing approximately 20 MW. The DPUC's contingent approval of this contract would become final if one or more of the seven projects having an approved contract (representing at least 20 MW) is unable to obtain a financing commitment letter. CL&P's share of the future costs or benefits under all these contracts will be paid by or refunded to CL&P's customers. A third round of solicitations is expected to be conducted by the Connecticut Clean Energy Fund (CCEF) for an additional 26 MW of recoverable energy generation by October 1, 2008.

Also pursuant to the Energy Independence Act, the DPUC conducted a request for proposal process and selected three generating projects to be built or modified that would be eligible to sign contracts for differences (CfDs) with CL&P and UI for a total of approximately 782 MW of capacity. The process also selected one new 5 MW demand response project. The CfDs obligate CL&P or UI to pay the difference between a set capacity price and the value that the projects receive in the New England Independent System Operator (ISO-NE) capacity markets. The terms of the contracts are for periods of up to 15 years and would be subject to another similar sharing agreement between CL&P and UI. These contracts have been approved by the DPUC and signed by either CL&P or UI, whichever is the primary

obligor. CL&P's portion of the costs and benefits of these contracts will be paid by, or refunded to, CL&P's customers. On October 5, 2007, NRG Energy, Inc. filed an appeal of the DPUC's decision selecting the generation projects. On February 13, 2008, the Superior Court dismissed NRG's appeal.

The Energy Efficiency Act requires CL&P and UI to negotiate in good faith to potentially enter into cost-of-service based contracts for the energy associated with the three above-mentioned generation projects that were awarded CfDs by the DPUC, for term lengths equivalent to the associated CfDs. These energy contracts must be approved by the DPUC after a finding that they will stabilize the cost of electricity for Connecticut ratepayers. Depending on its terms, a long-term contract to purchase energy from a project that is also under a CfD could result in CL&P consolidating these projects into its financial statements. CL&P would seek to recover from customers any costs that result from consolidation of a project. As of February 1, 2008, only one of the three CfD project developers has requested that CL&P enter into negotiations for such a contract. For further information, see Notes 5 and 3, "Derivative Instruments," to our consolidated financial statements contained in NU's and CL&P's Annual Report to Shareholders, respectively, and incorporated herein by reference.

In addition, the Energy Efficiency Act requires electric distribution companies to file with the Connecticut Energy Advisory Board (CEAB) an integrated resource plan (IRP) which includes an assessment of the state's energy and capacity resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards. CL&P and UI filed a joint IRP with the CEAB on January 2, 2008. The CEAB may modify or accept the plan prior to filing it with the DPUC by May 1, 2008.

The Energy Efficiency Act also requires electric distribution companies to file proposals with the DPUC to build cost-of-service peaking generation facilities. CL&P filed a qualification submission with the DPUC on February 1, 2008, proposing two sites for peaking generation, and will file a detailed proposal on or about March 3, 2008. For further information, see "Legislative Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," contained in our Annual Report to Shareholders which is incorporated herein by reference.

On February 27, 2008, the DPUC issued a final decision in a docket examining the manner of operation and accuracy of CL&P's electric meters. While finding that the meters generally operated within industry standards, the DPUC imposed significant new testing, analytical and reporting requirements on CL&P. The DPUC also found that CL&P failed to be responsive to customer complaints by refusing meter tests or not allowing customers to speak with supervisors. The decision acknowledges recent corrective actions taken by CL&P but requires changes in numerous customer service practices. The decision also places substantial new tracking and reporting obligations on CL&P. The decision does not fine CL&P but holds that possibility open if CL&P fails to meet benchmarks to be established in this docket.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases its energy requirements to serve its Standard Service and Supplier of Last Resort loads from a variety of competitive sources through periodic requests for proposals (RFPs). CL&P issues RFPs periodically for periods of up to three years to layer Standard Service full requirements supply contracts in order to mitigate market volatility for its residential and small and medium commercial and industrial customers. CL&P issues RFPs for Supplier of Last Resort service for larger commercial and industrial customers every three months. Currently, CL&P has in place contracts with various suppliers through 2010. The DPUC is evaluating whether it will implement any changes to the RFP process.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Distribution (Including Regulated Generation)

PSNH is primarily engaged in the generation, purchase, transmission, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2007, PSNH furnished retail franchise electric service to approximately 491,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of electricity generation assets. Approximately 70 MW of those generation assets are hydroelectric units. Included among these generating assets is a 50 MW wood-burning generating unit in Portsmouth, New Hampshire, which was converted from a coal-burning unit and went into full operation in December 2006.

The following table shows the sources of 2007 electric franchise retail revenues based on categories of customers:

	PSNH
Residential	44%
Commercial	40%
Industrial	15%
Other	1%
Total	100%

Rates

PSNH is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) which has jurisdiction over, among other things, rates, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service, management efficiency and construction and operation of facilities.

Default Energy Service (ES) Rates. PSNH's ES rate recovers PSNH's generation and purchased power costs, including an ROE on PSNH's generation assets. PSNH files for approval of updated ES rates periodically with the NHPUC to ensure timely recovery of its costs. PSNH defers for future recovery or refund any difference between its ES revenues and the actual costs incurred.

On December 28, 2007, the NHPUC approved an increase in the ES rate to $0.0882 per kWh, effective January 1, 2008. Among other items, the new rate reflects an increase in PSNH's authorized generation ROE to 9.81% effective January 1, 2008.

Under the terms of the order issued by the NHPUC approving PSNH's new wood-burning generation plant (Northern Wood Power Project), which replaced one of the three 50 MW boiler units at the coal-fired Schiller Station, certain revenue, credits and cost avoidances (revenue sources) are shared between PSNH and its customers. These revenue sources include sales of renewable energy certificates (RECs) to other utilities, brokers, or suppliers, and production tax credits. In any given year, if the combination of revenue sources falls short of a stipulated revenue level, PSNH and its customers each share half of any deficiency, and if the combination exceeds the stipulated revenue level, PSNH and its customers each share half of any excess. The Northern Wood Power Project entered commercial operation on December 1, 2006, and revenue sources exceeded stipulated levels in 2007 due to its performance and favorable pricing in the Massachusetts market for the RE Cs. As a result, customers and shareholders will share equally a benefit of about $9.2 million of incremental revenues for 2007. A majority of PSNH's share of these benefits will be recognized in 2008 when the 2007 RECs are delivered.

Although PSNH's customers are entitled to choose competitive energy suppliers, PSNH has experienced only a small amount of customer migration to date.

Delivery Service (DS) Rates. On May 30, 2006, PSNH filed a petition with the NHPUC requesting an increase in its DS rates. On May 25, 2007, the NHPUC approved a distribution and transmission rate case settlement agreement (PSNH rate settlement agreement) between PSNH, the NHPUC staff and the Office of Consumer Advocate. The PSNH rate settlement agreement provided for a $37.7 million annualized increase ($26.5 million estimated for distribution and $11.2 million estimated for transmission in base rates subject to tracking) that was effective on July 1, 2007, replacing a previous $24.5 million temporary distribution rate settlement increase that was effective on July 1, 2006. The $37.7 million includes a one-year revenue increase of approximately $9 million to recoup the difference between the temporary and the approved rates for the period July 1, 2006 through June 30, 2007. An additional delivery revenue increase of $3 mi llion took effect on January 1, 2008 with a final rate decrease of approximately $9 million scheduled for July 1, 2008.

Transmission Cost Adjustment Mechanism. On June 1, 2007, PSNH filed a petition with the NHPUC seeking to establish a Transmission Cost Adjusting Mechanism (TCAM) rate consistent with the PSNH rate settlement agreement. The TCAM rate filing was amended on June 6, 2007 to reflect updates to wholesale transmission rates that were made available to PSNH after the initial June 1, 2007 filing. The NHPUC issued an order on June 29, 2007 approving a TCAM rate of $0.00752 per kWh for the period July 1, 2007 through June 30, 2008.

Stranded Cost Recovery Charge (SCRC). Under New Hampshire law, the SCRC allows PSNH to recover its stranded costs. PSNH has financed a significant portion of its stranded costs through securitization by issuing rate reduction bonds secured by the right to recover these stranded costs from customers over time. It recovers the costs of these bonds through the SCRC rate. On an annual basis, PSNH files with the NHPUC an SCRC reconciliation filing for the previous year. For further information on PSNH rates, see "Regulatory

Developments and Rate Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in our Annual Report to Shareholders which is incorporated herein by reference.

Coal Procurement Docket: During the second quarter of 2006, the NHPUC opened a docket to review PSNH's coal procurement and coal transportation policies and procedures. A consultant hired by the NHPUC conducted an investigation and made certain preliminary findings and recommendations. PSNH responded to the consultants report and consulted with the NHPUC Staff. As a result of those discussions, PSNH agreed to many of the recommendations made concerning the conduct of its coal procurement activities. There will be no material adverse financial impact on PSNH as a result of implementing the Staff's recommendations.

Sources and Availability of Electric Power Supply

During 2007, about 70% of PSNH load was met through its own generation and long-term power supply rate orders and contracts with third parties. The remaining 30% of PSNH's load was met by short-term (less than one year) purchases and spot purchases in the competitive New England wholesale power market. PSNH expects to meet its load requirements in 2008 in a similar manner.

On May 11, 2007, New Hampshire Governor Lynch signed into law the "Renewable Energy Act," establishing renewable portfolio standards for electricity sold in the state, and ultimately requiring that 23.8% of the electricity sold to retail customers have direct ties to renewable sources by 2025. The renewable sourcing requirements begin in 2008 and increase each year to reach 23.8% by 2025. PSNH will be required to comply with these standards, which it plans to do primarily through the purchase of RECs or through Alternative Compliance Payments allowed under state law. PSNH expects that the additional costs incurred in meeting this new requirement will be recovered through PSNH’s energy service rates. For further information, see "Other Regulatory and Environmental Matters" in this Annual Report on Form 10-K.

WESTERN MASSACHUSETTS ELECTRIC COMPANY

Distribution

WMECO is engaged in the purchase, transmission, delivery and sale of electricity to residential, commercial and industrial customers. At December 31, 2007, WMECO furnished retail franchise electric service to approximately 206,000 retail customers in 59 cities and towns in the western third of Massachusetts. WMECO does not own any electricity generating facilities.

The following table shows the sources of 2007 electric franchise retail revenues based on categories of customers:

	WMECO
Residential	56%
Commercial	32%
Industrial	11%
Other	1%
Total	100%

Rates

WMECO is subject to regulation by the Massachusetts Department of Public Utilities (formerly the Department of Telecommunications and Energy) (DPU), which has jurisdiction over, among other things, rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities. WMECO's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. Massachusetts utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to cover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under state law, all of WMECO's customers are now entitled to choose their energy suppliers, while retaining WMECO as their distribution company. WMECO purchases electric power for and passes through the cost to those customers who do not choose a competitive energy supplier (basic service). Basic service charges are adjusted and reconciled on an annual basis. Most of WMECO's residential and smaller customers have continued to buy their power from WMECO at basic service rates. A greater proportion of large commercial and business customers have opted for a competitive energy supplier. As of December 31, 2007, approximately 15,000 or 7% out of nearly 206,000 customers had elected this option, representing about 45% of the energy delivered by WMECO.

WMECO collects its transmission costs through a transmission adjustment clause. The DPU approved the tracking mechanism in January 2002, which provides for annual adjustments, thereby allowing WMECO to recover all of its retail transmission expenses on a timely basis.

WMECO has also received regulatory orders allowing it to recover all or substantially all of its prudently incurred stranded costs. WMECO has financed a portion of its stranded costs through securitization by issuing rate reduction certificates secured by the right to recover stranded costs from customers over time. It is recovering the costs of securitization through rates.

Rate Case Settlement. WMECO implemented a $1 million rate increase on January 1, 2007 to reflect a distribution rate increase approved by the DPU in December 2006. An additional increase of $3 million became effective on January 1, 2008. Rates were also adjusted January 1, 2008 to include approved adjustments in various tracking mechanisms and new basic service contracts. For further information on WMECO rates, see "Regulatory Developments and Rate Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," contained in our Annual Report to Shareholders which is incorporated herein by reference.

Sources and Availability of Electric Power Supply

As noted above, WMECO does not own any generation assets and purchases its energy requirements from a variety of competitive sources through periodic RFPs. For basic service power supply, WMECO issues RFPs periodically, consistent with DPU regulations. For 2008, WMECO entered into an agreements on May 15, 2007, to secure 50% of residential, small commercial and industrial, and street lighting loads for the July 1, 2007 through June 30, 2008 period, and on November 13, 2007 to secure power for half of its residential, small commercial and industrial, and street lighting loads for the January 1 through December 31, 2008 period. WMECO will issue an RFP in the second quarter of 2008 to secure the remaining 50% of its residential, small commercial and industrial, and street lighting loads for the July 1 through December 31, 2008 period and 50% of the load for January 1, 2009 through June 30, 2009. For its large commercial and industrial customers, WMECO entered into an agreement on November 13, 2007 to secure power for the first quarter of 2008 and an agreement to secure power for the second quarter 2008 on February 12, 2008. RFPs will be issued quarterly to address the balance of the year.

LICAP AND FCM DEVELOPMENT

On December 1, 2006 a FERC-approved Forward Capacity Market settlement agreement was implemented, and the payment of fixed compensation to generators began. Several parties challenged the FERC's approval of the FCM settlement agreement and that challenge is pending in the Court of Appeals. The first forward capacity auction concluded in early February of 2008 for the capacity year of June of 2010 through May of 2011. The bidding reached the establishment minimum of $4.50 per kilowatt-month with 2,047MW of excess remaining capacity which means the effective capacity price will be $4.25 per kilowatt-month compared to the established price of $4.10 per kilowatt-month for the 12-month capacity period ending May 31, 2010. These costs are recoverable in all jurisdictions through the currently established rate structures.

For more information regarding CL&P, WMECO and PSNH state regulatory matters, see "Regulatory Developments and Rate Matters" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which is incorporated into this Annual Report on Form 10-K by reference.

REGULATED GAS DISTRIBUTION

Yankee Energy System, Inc. (Yankee) is the holding company of Yankee Gas and several immaterial non-utility subsidiaries, including NorConn Properties, Inc., which holds certain minor properties and facilities of Yankee and its subsidiaries, and Yankee Energy Financial Services Company, which was in the business of providing Yankee Gas customers and other energy end-users with financing primarily for energy equipment installations, but which is in the process of winding down its business operations.

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 200,000), and size of service territory (2,088 square miles). Total throughput (sales and transportation) for 2007 was 49.7 billion cubic feet (Bcf) compared with 45.2 Bcf in 2006. Yankee Gas provides firm gas sales service to customers who require a continuous gas supply throughout the year, such as residential customers who rely on gas for their heating, hot water and cooking needs, and commercial and industrial customers who choose to purchase gas from Yankee Gas. Yankee Gas also offers firm transportation service to its commercial and industrial customers who purchase gas from sources other than Yankee Gas as well as interruptible transportation and interruptible gas sales service to those certain commercial and industrial customers that have the capability to switch from natural gas to an alternative fuel

on short notice. Yankee Gas can interrupt service to these customers during peak demand periods or at any other time to maintain distribution system integrity.

In 2007, Yankee Gas completed construction of a liquefied natural gas (LNG) facility in Waterbury, Connecticut at a total cost of approximately $108 million. The LNG facility is capable of storing the equivalent of 1.2 Bcf of natural gas. The facility was put in service in July 2007 and filling of the LNG tank was completed by the end of October 2007 to serve customers during the 2007-2008 heating season.

Yankee Gas earned $22.6 million on total gas operating revenues of approximately $514 million for 2007. The following table shows the sources of 2007 total gas operating revenues:

	Yankee Gas
Residential	46%
Commercial	29%
Industrial	23%
Other	2%
Total	100%

For more information regarding Yankee Gas's financial results, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data," which includes Note 16, "Segment Information," within the notes to the consolidated financial statements, contained within our Annual Report to Shareholders, which is incorporated into this Annual Report Form 10-K by reference.

Although Yankee Gas is not subject to the FERC's jurisdiction, the FERC has limited oversight with respect to certain intrastate gas transportation that Yankee Gas provides. In addition, the FERC regulates the interstate pipelines serving Yankee Gas's service territory.

Rates

Yankee Gas is subject to regulation by the DPUC, which has jurisdiction over, among other things, rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities.

On December 29, 2006, Yankee Gas filed an application with the DPUC requesting an increase to its distribution service rate primarily for the recovery of costs associated with its newly constructed LNG facility. The filing also included increases in operating and maintenance and depreciation costs as well as a requested ROE of 10.5%. Yankee Gas negotiated a settlement with the Connecticut Office of Consumer Counsel (OCC) and the DPUC's Prosecutorial Division which resulted in an annualized increase of $22 million, or 4.2%, in Yankee Gas's base rates, net of expected pipeline and commodity cost savings resulting primarily from completion of Yankee Gas's LNG facility. The settlement included, among other things, the recovery of the costs of construction of its LNG facility, higher costs-of-service and an authorized ROE of 10.1%. Yankee Gas will return to ratepayers 100% of all earnings in excess of the allowed 10.1% ROE. The settl ement also allows Yankee Gas to defer certain costs for future recovery associated with the Department of Transportation's Office of Pipeline Safety regulations regarding pipeline integrity and improved pipeline safety. The DPUC approved the settlement on June 29, 2007 for rates effective July 1, 2007.

Yankee Gas recovers its cost of gas supplied to customers through a Purchased Gas Adjustment clause in its rate tariff. In 2005 and 2006, the DPUC issued decisions requiring an audit by an independent party of approximately $11 million in previously recovered PGA revenues associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. The audit was concluded, and a final report was submitted to the DPUC. A DPUC hearing was held on October 9, 2007. Management believes the unbilled sales and revenue adjustments and resulting charges to customers through the PGA clause for the audit period were appropriate and will be approved.

In 2007, in addition to the approximately $108 million capitalized for the LNG facility, Yankee Gas also capitalized $51.8 million related to reliability improvements, new customer connections and other initiatives.

REGULATED ELECTRIC TRANSMISSION

General

CL&P, PSNH and WMECO and most other New England utilities, generation owners and marketers are parties to a series of agreements that provide for coordinated planning and operation of the region's generation and transmission facilities and the market rules by which they 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 Operator (RTO) of the New England Transmission System since February 1, 2005. ISO-NE seeks to ensure the reliability of the 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 which portion of our major transmission facilities are regionalized throughout New England.

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 FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes the Regional Network Service (RNS) and Local Network Service (LNS) rate schedules, among other things. The RNS rate, administered by ISO-NE and billed to all New England transmission owners, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, which we administer, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not covered under the RNS rate, including 50% of the costs of construction work in progress (CWIP) on our remaining southwest Connect icut transmission projects. Both the LNS and RNS rates are based on projected costs and the projected in-service dates of transmission projects and provide for annual true-ups to actual costs. The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e. RNS, rental, etc.), thereby ensuring that we recover all regional and local revenue requirements as described in Tariff No. 3.

FERC ROE Decision

On October 31, 2006, the FERC issued a decision (FERC ROE decision) on a request by New England transmission owners, including CL&P, PSNH and WMECO, for a number of incentives related to new transmission facilities. The FERC set a base rate of 10.2% and effective November 1, 2006, the FERC added a 70 basis point adjustment, bringing the going-forward base ROE to 10.9%. In addition, the FERC approved (i) a 50 basis point adder for RTO participation and (ii) a 100 basis point adder for all new transmission investment where the projects have been identified as necessary by the ISO-NE regional planning process for a potential ROE of 12.4%.

On a going forward basis, our transmission capital program is largely comprised of regional infrastructure that is included within the regional planning process and thus eligible for FERC incentive treatment. Approximately 90% of our projected $3 billion transmission capital program for the period 2008 through 2012 is expected to be in this category, and therefore is expected to earn at the ROE of 12.4%.

On November 30, 2006, the New England transmission owners jointly filed a rehearing request for an additional 30 basis points for the base ROE to correct what appears to be an error in the FERC's base ROE calculation. Additionally, several New England Public Utilities Commissions, Consumer Counsels and Municipals filed a rehearing request challenging the 70 basis point adjustment and the 100 basis point adder for new regional transmission investment. On December 29, 2006, FERC issued a tolling order stating that it accepted the various rehearing requests and intends to act on them. This order allows the regional transmission owners to collect tariffs per the FERC ROE decision, subject to refund. The order did not include an action date, and until FERC takes some action on the rehearing requests, parties cannot bring an appeal to court.

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

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

The transmission segment of our regulated companies refunded approximately $2.2 million of revenues related to the July 26, 2007 FERC order (approximately $1.4 million after-tax) while the distribution segment received a net after-tax benefit of approximately $0.3 million as a result of these refunds. The refunds, net of benefits, totaling $1.1 million after-tax were recorded in 2007. For further information, see "Transmission Rate Matters and FERC Regulatory Issues" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," contained in our Annual Report to Shareholders which is incorporated herein by reference.

Other Rate Matters

On July 28, 2006, the FERC approved CL&P's proposal to allocate certain localized costs associated with the Bethel to Norwalk transmission project to all customers in Connecticut, as all of Connecticut will benefit from the reduction in congestion charges associated with the project. There are three load serving entities in Connecticut: CL&P, UI and the Connecticut Municipal Electric Energy Cooperative (CMEEC). These customers began to pay their allocated shares of the localized costs on a projected basis on June 1, 2006, subject to true-up based on actual costs. On December 26, 2006, FERC rejected a request by UI for rehearing of this decision. On February 23, 2007, UI appealed the FERC's orders to the D.C. Circuit Court of Appeals. On January 8, 2008, UI withdrew its appeal.

On November 1, 2007, we made a filing at FERC requesting recovery of deferred costs that we incurred as a result of our participation in the development, formation and startup of ISO-NE as the RTO for the New England region. We requested FERC's approval to transfer the costs to a regulatory asset account and to amortize them over a three year period beginning January 1, 2008. On December 31, 2007, the FERC conditionally accepted our proposed rate recovery subject to refund and subject to a compliance filing. For the compliance filing, FERC requested that we demonstrate that the proposed accounting will not cause any greater economic harm to our customers than if we had filed earlier and that we provide the purpose and nature of our costs in relation to the formation of the RTO.

Transmission Projects

Our ongoing transmission projects currently consist of three major transmission projects in southwest Connecticut;

- A 69-mile, 345 kilovolt (kV)/115 kV transmission project from Middletown to Norwalk, Connecticut. CL&P's portion of this project is estimated to cost approximately $1.05 billion. At February 20, 2008, CL&P's portion of this project was approximately 70% complete. As of December 31, 2007, CL&P had capitalized $593 million associated with this project. Although the project is scheduled to be completed by the end of 2009, construction of the project is currently ahead of schedule, and CL&P has reviewed the remaining work to determine whether it can be completed at an earlier date. As a result of this review, we now expect to complete this project in mid-2009.

- A two-cable, nine-mile, 115 kV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), construction of which began in October of 2006. This project is estimated to cost approximately $223 million. This project is scheduled to be completed by the end of 2008. At February 20, 2008, this project was approximately 73% complete. At December 31, 2007, CL&P had capitalized $133 million of associated costs.

- The replacement of the 11-mile undersea 138 kV electric transmission cable between Connecticut and Northport, Long Island, New York. Permitting, contracting, and cable manufacturing for this project is complete. CL&P and the Long Island Power Authority (LIPA) each own approximately 50% of this line. CL&P's portion of the project is estimated to cost $72 million. Marine construction activities commenced in October of 2007 and we expect that the project will be placed in service in the second half of 2008. The previous cables were decommissioned in September 2007, and approximately 94% of the cables were removed as of December 31, 2007, including all portions located in Connecticut. Installation of the new cable began in early February 2008. At February 20, 2008, the project was approximately 71% complete. At December 31, 2007, CL&P had capitalized $45 million of associated costs, including the co st of the new cable which was delivered in the fourth quarter of 2007.

In addition, CL&P's $335 million Bethel, Connecticut to Norwalk 345-kV transmission project, which entered service in late 2006, operated well in 2007 and reduced Connecticut congestion costs by approximately $150 million in its first full year in service.

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

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

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

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

We continue to review and analyze potential transmission solutions for New England's environmental and operating challenges, particularly, meeting renewable portfolio standard and regional greenhouse gas initiative requirements, and improving reliability and fuel diversity. In December, 2007 we delivered a presentation describing a conceptual set of high voltage direct current projects and their potential economic and environmental benefits at ISO-New England's Planning Advisory Committee meeting. We are continuing discussions with Canadian suppliers, New England transmission owners, New England state regulators and other key stakeholders to better understand the costs and benefits of new regional transmission solutions and the potential for a firm project proposal.

Transmission Rate Base

Under our FERC-approved tariffs, transmission projects enter rate base once they are placed in commercial operation. Additionally, 50% of our capital expenditures on each of our three major transmission projects still under construction in southwest Connecticut enter rate base during the construction period, with the remainder entering rate base once the projects are complete. At the end of 2007, our estimated transmission rate base was approximately $1.5 billion, including approximately $1.2 billion at CL&P, $175 million at PSNH and $80 million at WMECO. We forecast that our total transmission rate base will grow to approximately $3.9 billion by the end of 2012. This increase in transmission rate base is driven by the need to improve the capacity and reliability of our regulated transmission system.

A summary of projected year-end transmission rate base by regulated company is as follows (millions of dollars):

Company	2008	2009	2010	2011	2012
CL&P	$1,763	$2,168	$2,199	$2,515	$2,828
PSNH	295	306	367	371	458
WMECO	114	242	422	549	606
Totals	$2,172	$2,716	$2,988	$3,435	$3,892

For more information regarding Regulated Transmission matters, see "Transmission Rate Matters and FERC Regulatory Issues" and "Business Development and Capital Expenditures" under Item 7, "Management's

Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which is incorporated into this Annual Report on Form 10-K by reference.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The principal focus of our construction and capital improvement program is maintaining, upgrading and expanding the existing electric transmission and distribution system and natural gas distribution system. Our consolidated capital expenditures in 2007, including amounts incurred but not paid, cost of removal, allowance for funds used during construction and the capitalized portion of pension expense or income, totaled approximately $1.3 billion, almost all of which was expended by the regulated companies. The capital expenditures of these companies in 2008 are estimated to total approximately $1.3 billion. Of this amount, approximately $872 million is expected to be expended by CL&P, $275 million by PSNH, $85 million by WMECO and $56 million by Yankee Gas. This construction budget includes anticipated costs for all committed capital projects (i.e. generation, transmission, distribution, environmental compliance and others) and those reasonably expected to become committed projects in 2008. We expect to evaluate needs beyond 2008 in light of future developments, such as restructuring, industry consolidation, performance and other events. Increases in proposed distribution capital expenditures stems primarily from increasing labor and material costs and an aging infrastructure. The costs (both labor and material) that our regulated companies incur to construct and maintain their electric delivery systems have increased dramatically in recent years. These increases have been driven primarily by higher demand for commodities and electrical products, as well as increased demand for skilled labor. Our regulated companies have many major classes of equipment that are approaching or beyond their useful lives, such as old and obsolete distribution poles, underground primary cables and substation switchgear. Replacement of this equipment is extremely costly. Construction of the currently anticipated projects will r equire additional external debt financing at the subsidiary level and debt and equity financing at the NU Parent level.

CL&P’s transmission capital expenditures in 2007 totaled approximately $661 million. The increase in transmission segment capital expenditures in 2007 as compared with 2006 primarily relates to three major transmission projects under construction in southwest Connecticut: 1) the Middletown to Norwalk project, 2) the Glenbrook Cables project, and 3) the replacement of the underwater 138 kV cable between Connecticut and Long Island.

For 2008, CL&P projects transmission capital expenditures of approximately $538 million. During the period 2008 through 2012, CL&P plans to invest approximately $1.95 billion in transmission projects, including $571 million to complete the construction of its three southwest Connecticut projects.

In addition to its transmission projects, CL&P plans distribution capital expenditures to meet growth requirements and improve the reliability of its distribution system. In 2007, CL&P's distribution capital expenditures totaled approximately $283 million. Due to significant peak load growth in recent years, CL&P projects increasing distribution capital expenditures to approximately $334 million in 2008. CL&P plans to spend approximately $1.5 billion on distribution projects during the period 2008-2012. If all of the distribution and transmission projects are built as proposed, CL&P’s rate base for electric transmission is projected to increase from approximately $1.2 billion at the end of 2007 to approximately $2.8 billion by the end of 2012, and its rate base for distribution assets is projected to increase from approximately $1.9 billion to approximately $2.7 billion over the same period.

In 2007, PSNH's transmission capital expenditures totaled approximately $81 million, its distribution capital expenditures totaled $88 million and its generation capital expenditures totaled $35 million. For 2008, PSNH projects transmission capital expenditures of approximately $108 million, distribution capital expenditures of approximately $104 million and generation capital expenditures of approximately $63 million. The increase in distribution capital expenditures is mostly due to additional reliability expenditures, the new Cyber Security program and a number of major substation projects. The increase in generation capital expenditures is mostly due to the Merrimack 2 HP/IP and air heater tube replacement projects as well as higher expenditures for the Merrimack Scrubber project. During the period 2008-2012, PSNH plans to spend approximately $401 million on transmission projects and approximately $887 million on distribution and generation projects, including the installation of a wet scrubber to reduce mercury and sulfur emissions at its 440 MW coal-fired plant at Merrimack Station. If all of the distribution, generation and transmission projects are built as proposed, PSNH’s rate base for electric transmission is projected to increase from approximately $175 million at the end of 2007 to approximately $458 million by the end of 2012, and its rate base for distribution and generation assets is projected to increase from approximately $925 million to approximately $1.4 billion over the same period.

In 2007, WMECO's transmission capital expenditures totaled approximately $19 million and its distribution capital expenditures totaled approximately $34 million. In 2008, WMECO projects transmission capital expenditures of approximately $50 million and distribution capital expenditures of approximately $35 million. During the period 2008-2012, WMECO plans to spend approximately $648 million on transmission projects, with the bulk of that amount to be spent on the 115 kV Springfield Underground Cables project and the NEEWS 115 kV and 345 kV Overhead projects, and approximately $177 million on distribution projects. If all of the distribution and transmission

projects are built as proposed, WMECO's rate base for electric transmission is projected to increase from approximately $81 million at the end of 2007 to approximately $606 million by the end of 2012 and its rate base for distribution assets is projected to increase from approximately $372 million to approximately $503 million over the same period.

In 2007, Yankee Gas's capital expenditures totaled approximately $64 million, approximately $12 million of which was for the construction of its LNG facility. The facility was filled with LNG by the end of October 2007 to serve customers during the 2007/2008 heating season. The LNG facility was placed in service in July 2007 on budget with a final cost of approximately $108 million. In 2007, Yankee Gas also spent $23 million on its reliability improvement program, $20 million on connecting new customers, and $9 million on other initiatives, including meters and information technology systems. For 2008, Yankee Gas projects total capital expenditures of approximately $56 million. During the period 2008-2012, Yankee Gas plans on making approximately $305 million of capital expenditures. If all of Yankee Gas's projects are built as proposed, Yankee Gas's investment in its regulated assets is projected to increase from approximately $666 m illion at the end of 2007 to approximately $806 million by the end of 2012.

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

For more information regarding NU and its subsidiaries' construction and capital improvement programs, see "Business Development and Capital Expenditures" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which is incorporated into this Annual Report on Form 10-K by reference.

STATUS OF EXIT FROM COMPETITIVE ENERGY BUSINESSES

Since 2005, we have been in the process of exiting our competitive energy businesses and are now focusing exclusively on our regulated businesses. At December 31, 2007, our competitive businesses consisted solely of (i) Select Energy's few remaining wholesale marketing contracts and (ii) NU Enterprises' remaining energy services business, consisting of NGS, Boulos and the Connecticut division of SECI.

Four of the five remaining Select Energy wholesale sales contracts that were in the PJM power pool at the beginning of 2007 expired on May 31, 2007. The remaining PJM wholesale sales contract will expire on May 31, 2008. Select Energy's wholesale contract with The New York Municipal Power Agency (NYMPA) expires in 2013. In addition to the PJM and NYMPA contracts, Select Energy's only other long-term wholesale obligation is a long-term non-derivative contract to purchase the output of a certain generating facility in New England through 2012.

Also in 2007, the remaining contracts of SECI and the former Woods Electrical Co., Inc. wound down. For more information regarding the exit of the competitive businesses, see "NU Enterprises Divestitures" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 3, "Assets Held for Sale and Discontinued Operations," to the consolidated financial statements, contained within our Annual Report to Shareholders, which is incorporated into this Annual Report on Form 10-K by reference.

FINANCING

We paid dividends on our common shares totaling $121 million in 2007, compared to $112.7 million in 2006, reflecting increases in the quarterly dividend amount that were effective in the third quarters of 2006 and 2007.

Our total debt, including short-term debt, capitalized lease obligations and prior spent nuclear fuel liabilities, but not including rate reduction bonds or certificates, was approximately $3.7 billion as of December 31, 2007.

During 2007, the regulated companies issued the following debt:

On March 27, 2007, CL&P issued $150 million of its 10-year first and refunding mortgage bonds carrying a coupon rate of 5.375%, and $150 million of its 30-year first and refunding mortgage bonds carrying a coupon rate of 5.75%.

On August 17, 2007, WMECO issued $40 million of its 30-year unsecured senior notes with a coupon rate of 6.7%.

On September 17, 2007, CL&P issued $100 million of its 10-year first and refunding mortgage bonds carrying a coupon rate of 5.75%, and $100 million of its 30-year first and refunding mortgage bonds carrying a coupon rate of 6.375%.

On September 24, 2007, PSNH issued $70 million of its 10-year first mortgage bonds with a coupon rate of 6.15%.

At December 31, 2007, NU parent maintained a revolving credit facility of $500 million, and the regulated companies maintained a joint revolving credit facility of $400 million, both of which expire on November 6, 2010. At December 31, 2007, there were $42 million in borrowings and $27 million in letters of credit outstanding under the NU parent credit facility. There were $45 million of long-term borrowings by Yankee Gas outstanding under the regulated companies' facility at December 31, 2007. In addition, there were $10 million and $27 million in short-term borrowings by PSNH and Yankee Gas, respectively, outstanding under the regulated companies' facility at December 31, 2007.

In addition, CL&P has access to funds under an arrangement with its subsidiary, CL&P Receivables Corporation (CRC). CRC has an agreement with CL&P to purchase up to $100 million of an undivided interest in CL&P's accounts receivables and unbilled revenues, which CRC sells to a highly rated financial institution on a limited recourse basis. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to the servicing of those receivables. At December 31, 2007, CL&P had sold $20 million under this facility.

Financial Covenants in Credit Facilities. Under their revolving credit facility agreements, each of NU, CL&P, WMECO, PSNH and Yankee Gas must maintain a ratio of consolidated debt to total capitalization of no more than 65%. At December 31, 2007, NU, CL&P, WMECO, PSNH, and Yankee Gas were, and are expected to remain, in compliance with this ratio.

For more information regarding NU and its subsidiaries' financing, see "Notes to Consolidated Financial Statements" in NU's financial statements, the footnotes related to long-term debt, short-term debt, leases and the sale of accounts receivables, as applicable, in the notes to NU's, CL&P's, PSNH's, and WMECO's financial statements, and "Liquidity" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which are incorporated into this Annual Report on Form 10-K by reference.

NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and other New England electric utilities are the stockholders of three regional nuclear companies, Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company (MYAPC) and Yankee Atomic Electric Company (YAEC) (the Yankee Companies). Until recently, each Yankee Company owned a single nuclear generating unit –the Connecticut Yankee nuclear unit, the Maine Yankee nuclear unit, and the Yankee Rowe nuclear unit. The Yankee Companies have completed the physical decommissioning of their respective facilities and are now engaged in the long-term storage of their spent nuclear fuel. Each Yankee Company collects decommissioning and closure costs through wholesale FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail ra tes. The stock ownership percentages of CL&P, PSNH and WMECO in the Yankee Companies are set forth below:

	CL&P	PSNH	WMECO
Connecticut Yankee Atomic Power Company	34.5%	5.0%	9.5%
Maine Yankee Atomic Power Company	12.0%	5.0%	3.0%
Yankee Atomic Electric Company	24.5%	7.0%	7.0%

Our share of the obligations to support the Yankee Companies under FERC-approved rules is the same as the ownership percentages above.

For more information regarding decommissioning and nuclear assets, see "Deferred Contractual Obligations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," within our Annual Report to Shareholders, which is incorporated into this Annual report on Form 10-K by reference.

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including the FERC, the SEC, and various state and/or local regulatory authorities with jurisdiction over the industry and the service areas in which each of our companies operates, including the DPUC having jurisdiction over CL&P and Yankee Gas, the NHPUC having jurisdiction over PSNH, and the DPU having jurisdiction over WMECO.

Environmental Regulation

We are subject to various federal, state and local requirements with respect to water quality, air quality, toxic substances, hazardous waste and other environmental matters. Additionally, our major generation and transmission facilities may not be constructed or significantly modified without a review of the environmental impact of the proposed construction or modification by the applicable federal or state agencies. Compliance with increasingly stringent environmental laws and regulations, particularly air and water pollution control requirements, may limit operations or require substantial investments in new equipment at existing facilities.

Water Quality Requirements

The federal Clean Water Act requires every "point source" discharger of pollutants into navigable waters to obtain a National Pollutant Discharge Elimination System (NPDES) permit from the United States Environmental Protection Agency or state environmental agency specifying the allowable quantity and characteristics of its effluent. States may also require additional permits for discharges into state waters. We are in the process of obtaining or renewing all required NPDES or state discharge permits in effect for our facilities. Compliance with NPDES and state discharge permits has necessitated substantial expenditures and may require further significant expenditures, which are difficult to estimate, because of additional requirements or restrictions that could be imposed in the future, including requirements related to Sections 316(a) and 316(b) of the Clean Water Act for facilities owned by PSNH.

Air Quality Requirements

The Clean Air Act Amendments of 1990 (CAAA), as well as state laws in Connecticut, Massachusetts and New Hampshire, impose stringent requirements on emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Installation of continuous emissions monitors and expanded permitting provisions also are included.

In New Hampshire, the Multiple Pollutant Reduction Program was signed into law in May 2002. Under this law, NO_X, SO_2 and Carbon Dioxide (CO_2) emission are capped for current compliance beginning in 2007. A law was passed during the 2006 legislative session requiring reductions in emissions of mercury from coal-fired plants, including those owned by PSNH. The law requires PSNH to install a wet flue gas desulphurization system, known as "scrubber" technology, to reduce mercury emissions (with the co-benefit of reductions in SO_2 emissions as well) at Merrimack Station no later than July 1, 2013. PSNH currently anticipates that compliance with this law will cost $250 million, but this amount has the potential to increase materially as the project is undertaken, primarily as a result of changes in commodity prices and labor costs.

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by a group of northeastern states, including Massachusetts, New Hampshire and Connecticut, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fuel-fired electric generators. This initiative proposes to stabilize CO_2 emissions at current levels and require a 10% reduction from the initial 2009 permitted emissions levels by 2018. Each signatory state committed to propose for approval legislative and/or regulatory mechanisms to implement the program. The Connecticut Department of Environmental Protection (CDEP) released draft RGGI regulations on December 28, 2007 and had a public hearing on February 8, 2008. The CDEP plans to have these rules finalized by May 2008 and to participate in a proposed open regional auction of CO_2 allowances in June 2008. Connecticut has proposed an auction of 91% of allocat ed CO_2 allowances with the remainder set aside for certain clean energy projects. Connecticut has proposed the first compliance period for affected facilities to begin on January 1, 2009. Although neither CL&P nor Yankee Gas currently have any facilities subject to the RGGI program, CL&P expects the cost of purchased energy supply to increase due to RGGI requirements. NU Enterprises manages a facility in Connecticut under a non-derivative contract which will likely be required to purchase CO_2 allowances. Massachusetts Department of Environmental Protection and Division of Energy Resources released their draft RGGI regulations on August 10, 2007. The final rule is expected in early 2008 and Massachusetts also plans to participate in the June 2008 regional auction. Although WMECO has no facilities that would be subject to this rule, it also expects the cost of purchased energy to increase. PSNH is the only one of our regulated compani es that currently owns any generation assets that could be subject to the RGGI standards.

In New Hampshire, draft legislation has been proposed during this 2008 session that is consistent with the RGGI initiative. However, at this time because the draft legislation has not yet been finalized and because the cost of CO_2 allowances under RGGI cannot be identified with any certainty, we are unable to determine the actual cost of RGGI and its impact on customer rates.

On May 11, 2007, New Hampshire adopted renewable portfolio standards for electricity sold in the state which ultimately requires that 23.8% of the electricity sold to retail customers have direct ties to renewable sources by 2025. The renewable sourcing requirements begin in 2008 and increase each year to reach 23.8% by 2025. PSNH will be required to comply with these standards. We expect that the additional costs incurred to meet this new requirement will be recovered through PSNH's energy service rates.

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

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws were implemented, residues from operations were often disposed of by depositing or burying such materials on-site or disposing of them at off-site landfills or facilities. Typical materials disposed of include coal gasification waste, fuel oils, ash, gasoline and other hazardous materials that might contain polychlorinated biphenyls. It has since been determined that deposited or buried wastes, under certain circumstances, could cause groundwater contamination or create other environmental risks. We have recorded a liability for what we believe is, based upon currently available information, our estimated environmental investigation and/or remediation costs for waste disposal sites for which we expect to bear legal liability, and continue to evaluate the environmental impact of our former disposal practices. Under federal and state law, government age ncies and private parties can attempt to impose liability on us for such past disposal. At December 31, 2007, the liability recorded by us for our estimable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $25.8 million, representing 53 liabilities. All cost estimates were made in accordance with generally accepted accounting principles where investigation and/or remediation costs are probable and reasonably estimable. These costs could be significantly higher if additional remedial actions become necessary or when additional information as to the extent of contamination becomes available.

The most significant liabilities currently relate to future clean up costs at former manufactured gas plant (MGP) facilities. These facilities were owned and operated by predecessor companies to us from the mid-1800's to mid-1900's. By-products from the manufacture of gas using coal resulted in fuel oils, hydrocarbons, coal tar, purifier wastes, metals and other waste products that may pose risks to human health and the environment. We, through our subsidiaries, currently have partial or full ownership responsibilities at 28 former MGP sites. Of our total recorded liabilities of $25.8 million, a reserve of approximately $23.6 million has been established to address future investigation and/or remediation costs at MGP sites. In addition, remediation has been conducted at a coal tar contaminated river site in Massachusetts that is at least partially the responsibility of Holyoke Water Power Company (HWP), a subsidiary of NU, which previously own ed generating assets. The cost to clean up that contamination may be more significant than currently estimated, but the level and extent of contamination remains unknown. Any and all exposure related to this site is not subject to ratepayer recovery. An increase to the environmental reserve for this site would be recorded in earnings in future periods and may be material.

In the past, we or our subsidiaries have received other claims from government agencies and third parties for the cost of remediating sites not currently owned by us but affected by our past disposal activities and may receive additional such claims in the future. We expect that the costs of resolving claims for remediating sites about which we have been notified will not be material, but we cannot estimate the costs with respect to sites about which we have not been notified.

For further information on environmental liabilities, see Note 8B, "Commitments and Contingencies - Environmental Matters" contained within NU's 2007 Annual Report to Shareholders, which is incorporated into this Annual Report on Form 10-K by reference.

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from electric and magnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Although weak health risk associations reported in some epidemiology studies remain unexplained, most researchers, as well as numerous scientific review panels, considering all significant EMF epidemiology and laboratory studies, have concluded that the available body of scientific information does not support the conclusion that EMF affects human health.

We have closely monitored research and government policy developments for many years and will continue to do so. In accordance with recommendations of various regulatory bodies and public health organizations, we reduce EMF associated with new transmission lines by the use of designs that can be implemented without additional cost or at a modest cost. We do not believe that other capital expenditures are appropriate to minimize unsubstantiated risks.

FERC Hydroelectric Project Licensing

New Federal Power Act licenses may be issued for hydroelectric projects for terms of 30 to 50 years as determined by the FERC. Upon the expiration of an existing license, (i) the FERC may issue a new license to the existing licensee, or (ii) the United States may take over the project or (iii) the FERC may issue a new license to a new licensee, upon payment to the existing licensee of the lesser of the fair value or the net investment in the project, plus severance damages, less certain amounts earned by the licensee in excess of a reasonable rate of return.

PSNH owns nine hydroelectric generating stations with an aggregate of approximately 66.3 MW of capacity, with a current claimed capability representing winter rates, of approximately 69.5 MW. Of these nine plants, eight are licensed by the FERC under long-term licenses that expire on varying dates from 2009 through 2036. As a licensee under the Federal Power Act (FPA), PSNH and its licensed hydroelectric projects are subject to conditions set forth in the FPA and related FERC regulations, including provisions related to the condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment and severance damages and other matters.

FERC hydroelectric project licenses expire periodically and the generating facilities must be relicensed at such times. A new FERC license for PSNH’s Merrimack River Hydroelectric Project, which consists of the Amoskeag, Hooksett and Garvins Falls generating stations, was issued on May 18, 2007. PSNH's Canaan Hydroelectric Project is currently in FERC relicensing proceedings. The license for the Canaan Hydroelectric Project expires in 2009.

Licensed operating hydroelectric projects are not generally subject to decommissioning during the license term in the absence of a specific license provision which expressly permits the FERC to order decommissioning during the license term. However, the FERC has taken the position that under appropriate circumstances it may order decommissioning of hydroelectric projects at relicensing or may require the establishment of decommissioning trust funds as a condition of relicensing. The FERC may also require project decommissioning during a license term if a hydroelectric project is abandoned, the project license is surrendered or the license is revoked.

At this time, it appears unlikely that the FERC will order decommissioning of PSNH's hydroelectric projects at relicensing or that the projects will be abandoned, surrendered or the project licenses revoked. However, it is impossible to predict the outcome of the FERC relicensing proceedings with certainty, or to determine the impact of future regulatory actions on project economics. Until such time as a project is ordered to be decommissioned and the terms and conditions of a decommissioning order are known, any estimates of the cost of project decommissioning are preliminary and subject to change as new information becomes available.

EMPLOYEES

As of December 31, 2007, we employed a total of 5,869 employees, excluding temporary employees, of which 1,825 were employed by CL&P, 1,210 by PSNH, 337 by WMECO, 393 by Yankee Gas and 1,954 were employed by Northeast Utilities Service Company (NUSCO).

Approximately 2,217 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are covered by 11 union agreements.

INTERNET INFORMATION

Our website address is www.nu.com. We make available through our website a link to the SEC's EDGAR site, at which site NU's, CL&P's, WMECO's and PSNH's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports may be reviewed. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at Northeast Utilities, 107 Selden Street, Berlin, Connecticut 06037.

Item 1A. Risk Factors

We are subject to a variety of significant risks in addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" in Item 1, "Business," above. Our susceptibility to certain risks, including those discussed in detail below, could exacerbate other risks. These risk factors should be considered carefully in evaluating our risk profile.

The infrastructure of our transmission and distribution system may not operate as expected, and could require additional unplanned expense which could adversely affect our earnings.

Our ability to manage operational risk with respect to our transmission and distribution systems is critical to the financial performance of our business. Our transmission and distribution businesses face several operational risks, including the breakdown or failure of or damage to equipment or processes (especially due to age), accidents and labor disputes. The costs (both labor and material) that our regulated companies incur to construct and maintain their electric delivery systems have increased in recent years. These increases have been driven primarily by higher demand for commodities and electrical products, as well as increased demand for skilled labor. A significant percentage of our regulated company equipment is nearing or at the end of its life cycle, such as old and obsolete distribution poles, underground primary cables and substation switchgear. The failure of our transmission and distributions systems to operate as planned may result in increased capital investments, reduced earnings or unplanned increases in expenses, including higher maintenance costs. Any such costs which may not be recoverable from our ratepayers would have an adverse effect on our earnings.

Changes in regulatory or legislative policy, difficulties in obtaining siting, design or other approvals, global demand for critical resources, or environmental or other concerns, or construction of new generation may delay completion of or displace our transmission projects or adversely affect our ability to recover our investments or result in lower than expected rates of return.

The successful implementation of our transmission construction plans is subject to the risk that new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could impact our ability to meet our construction schedule and/or require us to incur additional expenses and may adversely affect our ability to achieve forecast levels of revenues. In addition, difficulties in obtaining required approvals for construction, or increased cost of and difficulty in obtaining critical resources as a result of global or domestic demand for such resources could cause delays in our construction schedule and may adversely affect our ability to achieve forecasted earnings.

The regulatory approval process for our planned transmission projects encompasses an extensive permitting, design and technical approval process. Various factors could result in increased cost estimates and delayed construction. These include environmental and community concerns and design and siting issues. Recoverability of all such investments in rates may be subject to prudence review at the FERC at the time such projects are placed in service. While we believe that all such expenses have been and will be prudently incurred, we cannot predict the outcome of future reviews should they occur.

In addition, to the extent that new generation facilities are proposed or built to address the region’s energy needs, the need for our planned transmission projects may be delayed or displaced, which could result in reduced transmission capital investments, reduced earnings, and limit future growth prospects.

The currently planned transmission projects are expected to help alleviate identified reliability issues and to help reduce customers' costs. However, if, due to further regulatory or other delays, the projected in-service date for one or more of these projects is delayed, there may be increased risk of failures in the existing electricity transmission system and supply interruptions or blackouts may occur which could have an adverse effect on our earnings.

The FERC has followed a policy of providing incentives designed to encourage the construction of new transmission facilities, including higher returns on equity and allowing facilities under construction to be placed in rate base before completion. Our projected earnings and growth could be adversely affected were FERC to reduce these incentives in the future below the level presently anticipated.

Increases in electric and gas prices and focus on conservation and self-generation by customers and changes in legislative and regulatory policy may adversely impact our business.

The nation's economy has been affected by significant increases in energy prices, particularly fossil fuels. The impact of these increases has led to increased electricity and natural gas prices for our customers, which has increased the focus on conservation, energy efficiency and self-generation on the part of customers and on legislative and regulatory policies. This focus on conservation, energy efficiency and self-generation may result in a decline in electricity and gas sales in our service territories. If any such declines were to occur without corresponding adjustments in rates, then our revenues would be reduced and our future growth prospects would be limited.

In addition, Connecticut, New Hampshire and Massachusetts have each announced policies aimed at increased energy efficiency and conservation. In connection with such policies, all three states have opened proceedings to investigate revenue decoupling as a mechanism to align the interests of customers and utilities relative to conservation. In Connecticut, the DPUC authorized decoupling via a rate design that is intended to recover proportionately greater distribution revenue through the fixed Customer and Demand charges, and proportionately less distribution revenue through the per kWh charges. At this time it is uncertain what mechanisms will ultimately be adopted by New Hampshire and Massachusetts and what impact these decoupling mechanisms will have on our companies.

Changes in regulatory policy may adversely affect our transmission franchise rights or facilitate competition for construction of large-scale transmission projects, which could adversely affect our earnings.

We have undertaken a substantial transmission capital investment program and expect to invest approximately $3 billion in regulated electric transmission infrastructure from 2008 through 2012.

Although our public utility subsidiaries have exclusive franchise rights for transmission facilities in our service area, the demand for improved transmission reliability could result in changes in federal or state regulatory or legislative policy that could cause us to lose the exclusivity of our franchises or allow other companies to compete with us for transmission construction opportunities. Such a change in policy could result in reduced transmission capital investments, reduce earnings, and limit future growth prospects.

Changes in regulatory and/or legislative policy could negatively impact regional transmission cost allocation rules.

The existing New England Transmission tariff allocates the costs of transmission investment that provide regional benefits to all customers in New England. As new investment in regional transmission infrastructure occurs in any one state, there is a sharing of these regional costs across all of New England. This regional cost allocation is contractually agreed to remain in place until 2010 by the Transmission Operations Agreement signed by all of the New England transmission owning utilities but can be changed with the approval of a majority of the transmission owning utilities thereafter. After 2010, certain changes to the terms of the Transmission Operations Agreement could have adverse effects on our distribution companies' local rates. We are working to retain the existing regional cost allocation treatment but cannot predict the actions of the states or utilities in the region.

Changes in regulatory or legislative policy could jeopardize our full recovery of costs incurred by our distribution companies.

Under state law, our utility companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Each of these companies prepares and submits periodic rate filings with their respective state regulatory commissions for review and approval. There is no assurance that these state commissions will approve the recovery of all costs prudently incurred by our regulated companies, such as for operation and maintenance, construction, as well as a return on investment on their respective regulated assets. Increases in these costs, coupled with increases in fuel and energy prices could lead to consumer or regulatory resistance to the timely recovery of such prudently incurred costs, thereby adversely affecting our cash flows and results of operations.

In addition, CL&P and WMECO procure energy for a substantial portion of their customers via requests for proposal on an annual, semi-annual or quarterly basis. CL&P and WMECO receive approvals of recovery of these contract prices from the DPUC and DPU, respectively. While both regulatory agencies have consistently approved solicitation processes, results and recovery of costs, management cannot predict the outcome of future solicitation efforts or the regulatory proceedings related thereto.

The energy requirements for PSNH are currently met primarily through PSNH's generation resources or fixed-price forward purchase contracts. PSNH’s remaining energy needs are met primarily through spot market or bilateral energy purchases. Unplanned forced outages of its generating plants could increase the level of energy purchases needed by PSNH and therefore increase the market risk associated with procuring the necessary amount

of energy to meet requirements. PSNH recovers these costs through its ES rate, subject to a prudence review by the NHPUC. We cannot predict the outcome of future regulatory proceedings related to recovery of these costs.

The loss of key personnel or the inability to hire and retain qualified employees could have an adverse effect on our business, financial condition and results of operations.

Our operations depend on the continued efforts of our employees. Retaining key employees and maintaining the ability to attract new employees are important to both our operational and financial performance. We cannot guarantee that any member of our management or any key employee at the NU parent or subsidiary level will continue to serve in any capacity for any particular period of time. In addition, a significant portion of our workforce, including many workers with specialized skills maintaining and servicing the electrical infrastructure, will be eligible to retire over the next five to ten years. Such highly skilled individuals cannot be quickly replaced due to the technically complex work they perform. We are developing strategic workforce plans to identify key functions and proactively implement plans to assure a ready and qualified workforce, but cannot predict the impact of these plans on our ability to hire and retain key employees.< /P>

Grid disturbances, severe weather, or acts of war or terrorism could negatively impact our business.

Because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business continuity due to a disruption or black-out caused by an event (severe storm, generator or transmission facility outage, or terrorist action) on an interconnected system or the actions of another utility. In addition, we are subject to the risk that acts of war or terrorism could negatively impact the operation of our system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results of operations.

Severe weather, such as ice and snow storms, hurricanes and other natural disasters, may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The cost of repairing damage to our operating subsidiaries' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial. The effect of the failure of our facilities to operate as planned would be particularly burdensome during a peak demand period, such as during the hot summer months.

A negative change in NU's credit ratings could require NU parent to post cash collateral and affect our ability to obtain financing.

NU parent’s senior unsecured debt ratings by Moody's Investors Service, Standard & Poor's, Inc. and Fitch Ratings are currently Baa2, BBB- and BBB, respectively, with stable outlooks. Were any of these ratings to decline to non-investment grade level, Select Energy could be asked to provide, as of December 31, 2007, collateral or letters of credit in the amount of $70.4 million to unaffiliated counterparties and collateral or letters of credit in the amount of $23.4 million to several independent system operators and unaffiliated local distribution companies (LDCs) under agreements largely guaranteed by NU parent. While our credit facilities are sufficient in amounts that would be adequate to meet cash calls at that level, our ability to meet any future cash calls would depend on our liquidity and access to bank lines and the capital markets at such time.

We expect to obtain the liquidity needed for our capital programs through bank borrowings, the issuance of long-term debt at the subsidiary level and debt and equity financing at the NU parent level. While we are reasonably confident these funds will be available on a timely basis and on reasonable terms, failure to obtain such financing could constrain our ability to finance regulated capital projects. In addition, any ratings downgrade of our securities or those of our subsidiaries, or any negative impacts on the credit market, generally, could negatively impact the cost or availability of capital.

Changes in wholesale electric sales could require Select Energy to acquire or sell additional electricity on unfavorable terms.

Select Energy's remaining wholesale sales contracts provide electricity to full requirements customers, including a regulated LDC and a municipal electric company. Select Energy provides a portion of the customer's electricity requirements. The volumes sold under these contracts vary based on the usage of the underlying retail electric customers, and usage is dependent upon factors outside of Select Energy's control, such as economic activity and weather. The varying sales volumes may differ from the supply volumes that Select Energy expected to utilize from electricity purchase contracts. Differences between actual sales volumes and supply volumes may require Select Energy to purchase additional electricity or sell excess electricity, both of which are subject to market conditions which change due to weather, plant availability, transmission congestion, and input fuel costs. The purchase of additional electricity at high prices or sale of exc ess electricity at low prices could negatively impact Select Energy's cost to serve the contracts.

We are subject to litigation which could result in large cash judgments against us.

We are engaged in litigation that could result in the imposition of large cash judgments against us. This litigation includes a civil lawsuit between us and Consolidated Edison, Inc. (Con Edison) relating to our October 13, 1999 Agreement and Plan of Merger.

We may also be subject to future litigation based on asserted or unasserted claims and cannot predict the outcome of any of these proceedings. Adverse outcomes in existing or future litigation could result in the imposition of substantial cash damage awards against us.

Further information regarding these legal proceedings, as well as other matters, is set forth in Item 3, "Legal Proceedings."

Costs of compliance with environmental regulations may increase and have an adverse effect on our business and results of operations.

Our subsidiaries' operations are subject to extensive federal, state and local environmental statutes, rules and regulations which regulate, among other things, air emissions, water discharges and the management of hazardous and solid waste. In particular, more stringent regulations of carbon dioxide and mercury emissions have been proposed in the various New England states in which we operate. Compliance with these requirements requires us to incur significant costs relating to environmental monitoring, installation of pollution control equipment, emission fees, maintenance and upgrading of facilities, remediation and permitting. The costs of compliance with existing legal requirements or legal requirements not yet adopted may increase in the future. An increase in such costs, unless promptly recovered, could have an adverse impact on our business and results of operations, financial position and cash flows.

In addition, global climate change issues have received an increased focus on the federal and state government levels which could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the power plants we own and operate as well as general utility operations. Although we would expect that any costs of these rules and regulations would be recovered from ratepayers, the impact of these rules and regulations on energy use by ratepayers and the ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time.

Any failure by us to comply with environmental laws and regulations, even if due to factors beyond our control, or reinterpretations of existing requirements, could also increase costs. Existing environmental laws and regulations may be revised or new laws and regulations seeking to protect the environment may be adopted or become applicable to us. Revised or additional laws could result in significant additional expense and operating restrictions on our facilities or increased compliance costs which may not be fully recoverable in distribution company rates for generation. The cost impact of any such legislation would be dependent upon the specific requirements adopted and cannot be determined at this time. For further information, see Item 1, "Business - Other Regulatory and Environmental Matters - Environmental Regulation."

Item 1B. Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2. Properties

Transmission and Distribution System

At December 31, 2007, our electric operating subsidiaries owned 196 transmission and 267 distribution substations that had an aggregate transformer capacity of 28,282,150 kilovolt amperes (kVa) and 2,253,520 kVa, respectively; 3,091 circuit miles of overhead transmission lines ranging from 69 KV to 345 KV, and 242 cable miles of underground transmission lines ranging from 69 KV to 345 KV; 34,760 pole miles of overhead and 2,817 conduit bank miles of underground distribution lines; and 532,416 underground and overhead line transformers in service with an aggregate capacity of 35,810,412 kVa.

Electric Generating Plants

As of December 31, 2007, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (kilowatts)
Total - Fossil-Steam Plants	(7 units)	1952-78	994,845
Total - Hydro-Conventional	(20 units)	1917-83	70,329
Total - Internal Combustion	(5 units)	1968-70	102,961
Total PSNH Generating Plant	(32 units)		1,168,135

*Claimed capability represents winter ratings as of December 31, 2007. The nameplate capacity of the generating plants is approximately 1,200 MW.

Neither CL&P nor WMECO owned any electric generating plants during 2007.

Yankee Gas

At December 31, 2007, Yankee Gas owned 27 gate stations, approximately 270 district regulator stations and 3,200 miles of main gas pipelines. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut as well as propane facilities in Danbury, Kensington and Vernon, Connecticut.

Franchises

CL&P. Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, CL&P has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to provide electric transmission and distribution services in the respective areas in which it is now supplying such service.

In addition to the right to provide electric transmission and distribution services as set forth above, the franchises of CL&P include, among others, limited rights and powers, as set forth in Title 16 of the Connecticut General Statutes and the special acts of the General Assembly constituting its charter, to manufacture, generate, purchase and/or sell electricity at retail, including to provide Standard Service, Supplier of Last Resort service and backup service, to sell electricity at wholesale and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of CL&P include the power of eminent domain. Title 16 of the Connecticut General Statutes was amended by Public Act 03-135, "An Act Concerning Revisions to the Electric Restructuring Legislation," to prohibit an electric distribution company from owning or operating generation assets. However, Public Act 05-01, "An Act Concerning Energy Independence," allows CL&P to own up to 200 MW of peaking facilities if the DPUC determines that such facilities will be more cost effective than other options for mitigating FMCCs and LICAP costs. In addition, Section 83 of Public Act 07-242, "An Act Concerning Electricity and Energy Efficiency" states that if an existing electric generating plant located in Connecticut is offered for sale, then an electric distribution company, such as CL&P, would be eligible to purchase the generation plant upon obtaining prior approval from the DPUC and a determination by the DPUC that such purchase is in the public interest.

PSNH. The NHPUC, pursuant to statutory requirements, has issued orders granting PSNH exclusive franchises to distribute electricity in the respective areas in which it is now supplying such service.

In addition to the right to distribute electricity as set forth above, the franchises of PSNH include, among others, rights and powers to manufacture, generate, purchase, and transmit electricity, to sell electricity at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on certain public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The distribution and transmission franchises of PSNH include the power of eminent domain.

WMECO. WMECO is authorized by its charter to conduct its electric business in the territories served by it, and has locations in the public highways for transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and for extensions of lines in public highways. Further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. In addition, WMECO has been granted easements for its lines in the Massachusetts Turnpike by the Massachusetts Turnpike Authority and pursuant to state laws, has the power of eminent domain.

The Massachusetts restructuring legislation defines service territories as those territories actually served on July 1, 1997 and following municipal boundaries to the extent possible. The restructuring legislation further provides that until terminated by law or otherwise, distribution companies shall have the exclusive obligation to serve all retail customers within their service territories and no other person shall provide distribution service within such service territories without the written consent of such distribution companies. Pursuant to the Massachusetts restructuring legislation, the DPU (then, the Department of Telecommunications and Energy) was required to define service territories for each distribution company, including WMECO. The Department of Telecommunications and Energy subsequently determined that there were advantages to the exclusivity of service territories and issued a report to the Massachusetts Legislature recommending against, in t his regard, any changes to the restructuring legislation.

Holyoke Water and Power Company and Holyoke Power and Electric Company. HWP, and its wholly owned subsidiary HP&E, are authorized by their charters to conduct their businesses in the territories served by them. In connection with the sale of certain of HWP's and HP&E's assets to the city of Holyoke Gas and Electric Department (HG&E) effective December 2001, HWP agreed not to distribute electricity at retail in Holyoke and surrounding towns unless other sellers can legally compete with HG&E, and to amend the charters of HWP and HP&E to reflect that limitation.

The two companies have locations in the public highways for their transmission lines. Such locations are granted pursuant to the laws of Massachusetts by the Massachusetts Department of Public Works or by local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and, for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. HP&E has no retail service territory area and sells electric power exclusively at wholesale.

Yankee Gas. Yankee Gas directly and from its predecessors in interest holds valid franchises to sell gas in the areas in which Yankee Gas supplies gas service. Generally, Yankee Gas holds franchises to serve customers in areas designated by those franchises as well as in most other areas throughout Connecticut so long as those areas are not occupied and served by another gas utility under a valid franchise of its own or are not subject to an exclusive franchise of another gas utility. Yankee Gas’s franchises are perpetual but remain subject to the power of alteration, amendment or repeal by the General Assembly of the State of Connecticut, the power of revocation by the DPUC and certain approvals, permits and consents of public authorities and others prescribed by statute. Generally, Yankee Gas’s franchises include, among other rights and powers, the right and power to manufacture, generate, purchase, transmit and distribute gas and to erect and maintain certain facilities on public highways and grounds, and the right of eminent domain, all subject to such consents and approvals of public authorities and others as may be required by law.

Item 3. Legal Proceedings

1. Consolidated Edison, Inc. v. NU - Merger Litigation

On March 5, 2001, Con Edison advised us that it was unwilling to close its merger with us on the terms set forth in our 1999 merger agreement (the Merger Agreement). On March 6, 2001, Con Edison filed suit in federal court in New York City seeking a declaratory judgment that we had suffered a material adverse change, as defined in the Merger Agreement, and that Con Edison was therefore excused from performing its obligations under the merger agreement. On March 12, 2001, we filed suit against Con Edison seeking to recover the merger premium, which totaled over $1 billion, for the benefit of our shareholders. On May 11, 2001, Con Edison filed an amended complaint seeking, in addition to the relief in its original complaint, an award of money damages of at least $314 million to compensate it for what it claims is the portion of the projected synergy savings that would have inured to the benefit of former Con Edison shareholders if the merger had been consum mated and the estimated savings had been realized. Con Edison also sought to recover its merger related expenses, which it claims were approximately $32 million.

On October 12, 2005, the United States Court of Appeals for the Second Circuit issued a decision concluding that our shareholders did not have the right to sue Con Edison for the merger premium as a result of its alleged breach of the Merger Agreement. The ruling left intact the remaining claims between us and Con Edison for breach of contract, which include our claim for recovery of costs and expenses of approximately $27 million, and Con Edison's claim for its alleged synergy damages plus expenses of $32 million. Any award of damages would also include prejudgment interest on the amount of damages awarded from the date of the filing of the claim.

On January 31, 2008, the trial judge denied a series of motions by both us and Con Edison that had been pending for more than one year, including our motion for an order dismissing Con Edison's synergy damage claim and ordered the parties to be trial ready on four days' notice beginning March 21, 2008.

It is not possible to predict either the outcome of this matter or its ultimate effect on us.

2. NRG Bankruptcy

On May 14, 2003, NRG and certain of its affiliates filed for Chapter 11 protection in the United States Bankruptcy Court for the Southern District of New York (Bankruptcy Court). The filing affects relationships between various NU companies and the NRG companies, as follows:

A. Station Service

NRG has disputed its responsibility to pay for the provision of station service by CL&P to NRG's Connecticut generating plants (approximately $28 million, including late charges). The FERC issued a decision on December 20, 2002 that NRG had agreed that station service from CL&P would be subject to CL&P's applicable retail rates, and that states (i.e., the DPUC) have jurisdiction over the delivery of power to end users even where power is not delivered via distribution facilities. NRG refused CL&P's subsequent demand for payment, and on April 3, 2003, CL&P petitioned the DPUC for a declaratory order enforcing the FERC's December 20, 2002 decision. Prior to the issuance of a decision by the DPUC, NRG filed a petition under Chapter 11 of the U.S. Bankruptcy Code, staying any further action by the DPUC. On December 17, 2003, the DPUC affirmatively stated that CL&P had been appropriately administering its station service rates. On January 8, 2008, CL&P and NRG filed a confidential proposed settlement with the DPUC, which would settle the competing claims. On January 28, 2008, the DPUC issued a final decision in CL&P’s rate case proceeding in which it also approved the confidential settlement between CL&P and NRG. CL&P and NRG signed the settlement agreement, which did not, and is not expected to, have a material adverse effect on CL&P, in February 2008.

B. Yankee Gas

On October 9, 2002, NRG informed Yankee Gas that its affiliate, Meriden Gas Turbines, LLC (MGT), was permanently shutting down or abandoning its Meriden power plant project, and requested that Yankee Gas cease its construction activities and begin an orderly wind down of its work relating to the project. Based on NRG's statement that it expected that Yankee Gas would draw on a $16 million letter of credit (LOC), Yankee Gas drew down the full amount of the LOC. On November 12, 2002, MGT filed suit against Yankee Gas in Meriden Superior Court, claiming that Yankee Gas breached the agreement with MGT (MGT Agreement), and seeking a declaratory ruling from the court that Yankee Gas wrongfully drew down the $16 million LOC. In April 2003, Yankee Gas filed its answer to MGT's complaint and asserted a counterclaim to recover its losses arising out of MGT's termination of the MGT Agreement. Yankee Gas and NRG signed a confidential settlement agreement which settle d the competing claims in February 2008. The settlement did not, and is not expected to have a material adverse effect on Yankee Gas.

C. Congestion Charges

On August 5, 2002, CL&P withheld the past due congestion charges from its payment to NRG pursuant to contractual provisions allowing the withholding of disputed sums. CL&P continued to withhold congestion charges from its monthly payments to NRG, through March 1, 2003, and at present is withholding approximately $28 million. On November 28, 2001, CL&P filed a complaint against NRG in Connecticut Superior Court alleging breach of contract arising from the failure of NRG to pay approximately $29.6 million of socialized congestion charges. The case was removed to U.S. District Court for the District of Connecticut. NRG filed a counterclaim seeking recovery of all amounts CL&P has withheld. The court granted CL&P's motion for summary judgment and entered judgment in CL&P’s favor on all counts on July 25, 2007.

3. Yankee Companies v. U.S. Department of Energy

The Yankee Companies commenced litigation in 1998 against the United States Department of Energy (DOE) charging that the federal government breached contracts it entered into with each company in 1983 under the Nuclear Waste Policy Act of 1982 to begin removing spent nuclear fuel from the respective nuclear plants no later than January 31, 1998 in return for payments by each company into the Nuclear Waste Fund. The funds for those payments were collected from regional electric customers. The Yankee Companies initially claimed damages for incremental spent nuclear fuel storage, security, construction and other costs through 2010.

In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same period as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE is established in the Yankee Companies' FERC-approved rate settlement agreement, although implementation will be subject to final determination of FERC. CL&P, PSNH and WMECO expect to pass any recovery onto their customers, therefore, no earnings impact is expected to result. In December 2006, the DOE appealed the decision, and the Yankee Companies filed cross-appeals. The appeal is expected to be argued in 2008 with a decision from the Court of Appeals to follow. The application of any damages which are ultimately recovered to benefit customers is established in the Yankee Companies' FERC-approved rate settlement agreements, although implementation will be subject to the final determination of the FERC.

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

4. Connecticut MGP Cost Recovery

On August 5, 2004, Yankee Gas and CL&P (NU Companies) demanded contribution from UGI Utilities, Inc. (UGI) of Pennsylvania for past and future remediation costs related to historic MGP operations on thirteen sites currently or formerly owned by the NU Companies (Yankee Gas is responsible for ten of the sites, CL&P for two of the sites, and both companies share responsibility for one site) in a number of different locations throughout the State of Connecticut. The NU Companies alleged that UGI controlled operations of the plants at various times throughout the period 1883 to 1941, when UGI was forced to divest its interests. Investigations and remediation expenditures at the sites to date total over $20 million, and projected potential remediation costs for all sites, based on litigation modeling assumptions, could total as much as $232 million. At this point, we are unable to estimate the potential costs associated with this matter.

In September 2006, the NU Companies filed a complaint against UGI in the U.S. District Court for the District of Connecticut seeking a fair and equitable contribution for the actual and anticipated remediation costs related to the former MGP operations. Discovery is scheduled through July 2008.

5. Dominion Nuclear-Station Service

On July 24, 2006, Dominion Nuclear Connecticut, Inc. (DNCI) filed a complaint at FERC, claiming that, because as of December 1, 2005, DNCI sought to "self-supply" its station service power through the ISO-NE settlement system rather than from CL&P as a Transitional Standard Service retail customer, it is not required to buy retail delivery service for that power. On August 14, 2006, CL&P answered the complaint, supported by the Connecticut DPUC, OCC and the AG.

On September 22, 2006, FERC issued an order finding that CL&P is not authorized to impose local distribution charges for station power delivery service on DNCI, and directed CL&P to cease charging DNCI retroactive to December 1, 2005. Since that date, DNCI has withheld approximately $1.7 million (including interest). CL&P sought rehearing and clarification on October 23, 2006. On May 27, 2007 FERC denied CL&P's rehearing and clarification request stating that CL&P is not authorized to charge Dominion local distribution charges to deliver station service to Millstone through transmission lines. On January 28, 2008, the DPUC issued a final decision in CL&P's rate case proceeding, which essentially reimburses CL&P for its net station service receivable for Dominion.

6. Other Legal Proceedings

The following sections of Item 1, "Business" discuss additional legal proceedings: See "Regulated Electric Distribution," "Regulated Gas Operations," and "Regulated Electric Transmission" for information about various state restructuring and rate proceedings, civil lawsuits related thereto, and information about proceedings relating to power, transmission and pricing issues; "Nuclear Decommissioning" for information related to high-level nuclear waste; and "Other Regulatory and Environmental Matters" for information about proceedings involving surface water and air quality requirements, toxic substances and hazardous waste, EMF, licensing of hydroelectric projects, and other matters. In addition, see Item 1A, "Risk Factors" for general information about several significant risks.

Executive Officers of the Registrant

This information is provided by NU in reliance on General Instruction G of Form 10-K.

Name	Age	Business Experience During Past 5 Years
Gregory B. Butler	50	Senior Vice President and General Counsel of NU since December 1, 2005 and of CL&P, PSNH and WMECO, subsidiaries of NU, since March 9, 2006, and a Director of Northeast Utilities Foundation, Inc. since December 1, 2002; previously Senior Vice President, Secretary and General Counsel of NU from August 31, 2003 to December 1, 2005; Vice President, Secretary and General Counsel of NU from May 1, 2001 through August 30, 2003.
Peter J. Clarke	46	Vice President of Shared Services of NUSCO, a subsidiary of NU, since January 1, 2008, and performs policy-making functions for NU. Previously Vice President - Customer Operations of CL&P and Yankee Gas Services Company from July 1, 2006 to December 31, 2007; Vice President - Customer Operations and Relations of CL&P from January 17, 2005 to June 30, 2006; and Director - System Projects of CL&P from March 11, 2002 to January 16, 2005.
Cheryl W. Grisé	55	Executive Vice President of NU from December 1, 2005 to July 1, 2007; Chief Executive Officer of CL&P, PSNH and WMECO from September 10, 2002 to January 15, 2007, a Director of CL&P from May 1, 2001 to January 15, 2007, of PSNH from May 14, 2001 to January 15, 2007 and of WMECO from June 2001 to January 15, 2007; previously President - Utility Group of NU from May 2001 to December 1, 2005.

Jean M. LaVecchia	56	Vice President - Human Resources of NUSCO, a subsidiary of NU, since June 30, 2005, and performs policy-making functions for NU; also a Director of Northeast Utilities Foundation since January 30, 2007. Previously Vice President - Human Resources and Environmental Services from May 1, 2001 to June 30, 2005. Performs policy-making functions for NU.
David R. McHale	47	Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO since January 1, 2005 and a Director of PSNH and WMECO since January 1, 2005 and CL&P since January 15, 2007 and a Director of Northeast Utilities Foundation since January 1, 2005; previously Vice President and Treasurer of NU, WMECO and PSNH from July 1998 to December 31, 2004.
Leon J. Olivier	59	Executive Vice President - Operations of NU since February 13, 2007; Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007; Director of PSNH and WMECO since January 17, 2005 and a Director of CL&P since September 2001; Previously Executive Vice President of NU from December 1, 2005 to February 13, 2007; President - Transmission Group of NU from January 17, 2005 to December 1, 2005; President and Chief Operating Officer of CL&P from September 2001 to January 2005.
Shirley M. Payne	56	Vice President - Accounting and Controller of NU since February 13, 2007, and of CL&P, PSNH and WMECO since January 29, 2007. Previously Vice President, Corporate Accounting and Tax of TECO Energy, Inc. from July 2000 to January 26, 2007 and Tax Officer of TECO Energy, Inc. from April 1999 to January 26, 2007.
James B. Robb	47	Senior Vice President, Enterprise Planning and Development of NUSCO since September 4, 2007, and performs policy-making functions for NU. Previously Managing Director, Russell Reynolds Associates from December 2006 to August 2007; Entrepreneur in Residence, Mohr Davidow Ventures from March 2006 to November 2006; Senior Vice President, Retail Marketing, Reliant Energy, Inc. from December 2003 to December 2006; Senior Vice President, Performance Management, Reliant Resources, Inc. from November 2002 to December 2003.
Charles W. Shivery	62	Chairman of the Board, President and Chief Executive Officer of NU since March 29, 2004; Chairman and a Director of CL&P, PSNH and WMECO since January 19, 2007 and a Director of Northeast Utilities Foundation since March 3, 2004. Previously, President (interim) of NU from January 1, 2004 to March 29, 2004; President - Competitive Group of NU and President and Chief Executive Officer of NU Enterprises, Inc., from June 2002 through December 2003.

None of the above Executive Officers serves as an Executive Officer pursuant to any agreement or understanding with any other person.

Item 4. Submission Of Matters To a Vote of Security Holders

No event that would be described in response to this item occurred with respect to us or CL&P.

The information called for by Item 4 is omitted for PSNH and WMECO pursuant to Instruction I (2)(c) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries.)

Part II

Item 5. Market for The Registrants' Common Equity and Related Stockholder Matters

NU. Our common shares 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 closing sales prices for the past two years, by quarters, are shown below.

Year	Quarter	High	Low
2007	First	$ 32.77	$ 27.40
	Second	33.53	27.37
	Third	29.42	26.93
	Fourth	32.83	27.98
2006	First	$ 20.21	$ 19.25
	Second	20.97	19.24
	Third	23.57	20.84
	Fourth	28.81	23.38

There were no purchases made by or on behalf of our company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of common stock during the fourth quarter of the year ended December 31, 2007. Information with respect to the performance of our common shares is contained in the "Share Performance Chart" from our 2007 Annual Report to Shareholders, which information is incorporated herein by reference.

As of January 31, 2008, there were 47,891 common shareholders of our company on record. As of the same date, there were a total of 175,969,591 common shares issued, including 1,110,400 unallocated Employee Stock Ownership Plan (ESOP) shares held in the ESOP trust.

On February 12, 2008, our Board of Trustees declared a dividend of 20 cents per share, payable on March 31, 2008, to shareholders of record as of March 1, 2008.

On November 13, 2007, our Board of Trustees declared a dividend of 20 cents per share, payable on December 31, 2007, to shareholders of record as of December 1, 2007.

On May 7, 2007, our Board of Trustees declared a dividend of 20 cents per share, payable on September 28, 2007, to shareholders of record as of September 1, 2007.

On April 10, 2007, our Board of Trustees declared a dividend of 18.75 cents per share, payable on June 29, 2007, to shareholders of record on June 1, 2007.

On February 13, 2007, our Board of Trustees declared a dividend of 18.75 cents per share, payable on March 31, 2007, to shareholders of record as of March 1, 2007.

On November 13, 2006, our Board of Trustees declared a dividend of 18.75 cents per share, payable on December 30, 2006, to shareholders of record as of December 1, 2006.

On May 9, 2006, our Board of Trustees declared a dividend of 18.75 cents per share, payable on September 29, 2006, to shareholders of record as of September 1, 2006.

On April 11, 2006, our Board of Trustees declared a dividend of 17.5 cents per share, payable on June 30, 2006, to shareholders of record on June 1, 2006.

On February 14, 2006, our Board of Trustees declared a dividend of 17.5 cents per share, payable on March 31, 2006, to shareholders of record as of March 1, 2006.

Information with respect to dividend restrictions for us, CL&P, PSNH, and WMECO is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity" and in the "Notes to Consolidated Financial

Statements," within our company's and each company's respective 2007 Annual Reports to Shareholders, which information is incorporated herein by reference.

CL&P, PSNH and WMECO. There is no established public trading market for the common stock of CL&P, PSNH and WMECO. The common stock of CL&P, PSNH and WMECO is held solely by NU.

During 2007 and 2006, CL&P approved and paid $79.2 million and $63.7 million, respectively, of common stock dividends to NU.

During 2007 and 2006, PSNH approved and paid $30.7 million and $41.7 million, respectively, of common stock dividends to NU.

During 2007 and 2006, WMECO approved and paid $12.8 million and $7.9 million, respectively, of common stock dividends to NU.

For information regarding securities authorized for issuance under equity compensation plans, see Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters," included in this Annual Report on Form 10-K.

Item 6. Selected Financial Data

NU. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within our 2007 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within CL&P's 2007 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within PSNH's 2007 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within WMECO's 2007 Annual Report, which information is incorporated herein by reference.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

NU. Reference is made to information under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within our 2007 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within CL&P's 2007 Annual Report, which information is incorporated herein by reference.

PSNH. With respect to PSNH's results of operations, reference is made to information under the heading "Results of Operations" contained within PSNH's 2007 Annual Report, which information is incorporated herein by reference.

WMECO. With respect to WMECO's results of operations, reference is made to information under the heading "Results of Operations" contained within WMECO's 2007 Annual Report, which information is incorporated herein by reference.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market Risk Information

Select Energy utilizes the sensitivity analysis methodology to disclose quantitative information for its commodity price risks (including where applicable capacity and ancillary components). Sensitivity analysis provides a presentation of the potential loss of future earnings, fair values or cash flows from market risk-sensitive instruments over a selected time period due to one or more hypothetical changes in commodity price components, or other similar price changes. Under sensitivity analysis, the fair value of the portfolio is a function of the underlying commodity components, contract prices and market prices represented by each derivative contract. For swaps, forward contracts and options, fair value reflects our best estimates considering over-the-counter quotations, time value and volatility factors of the underlying commitments. Exchange-traded futures and options are recorded at fair value based on closing exchange prices. As the NU Enterp rises' businesses are exited, the risks associated with commodity prices are expected to be reduced.

NU Enterprises - Wholesale Portfolio: When conducting sensitivity analyses of the change in the fair value of Select Energy's wholesale portfolio, which includes a non-derivative power purchase contract, which would result from a hypothetical change in the future market

price of electricity, the fair values of the contracts are determined from models that take into consideration estimated future market prices of electricity, the volatility of the market prices in each period, as well as the time value factors of the underlying commitments.

A hypothetical change in the fair value of the wholesale portfolio was determined assuming a 10% change in forward market prices. At December 31, 2007, Select Energy has calculated the market price resulting from a 10% change in forward market prices of those contracts. A 10% increase in prices for all products would have resulted in a pre-tax increase in fair value of $0.9 million and a 10% decrease in prices for all products would have resulted in a pre-tax decrease in fair value of $1.3 million. A 10% increase in energy prices would have resulted in a $6.8 million pre-tax decrease, and a 10% decrease in energy prices would have resulted in a $6.4 million pre-tax increase. A 10% increase/(decrease) in capacity prices would have resulted in a $2.2 million pre-tax increase/(decrease). A 10% increase/(decrease) in ancillary prices would have resulted in a $5.5 million pre-tax increase/(decrease).

The impact of a change in electricity and natural gas prices on Select Energy's wholesale transactions at December 31, 2007 are not necessarily representative of the results that will be realized. These transactions are accounted for at fair value, and changes in market prices impact earnings.

Other Risk Management Activities

Interest Rate Risk Management: We manage our interest rate risk exposure in accordance with our written policies and procedures by maintaining a mix of fixed and variable rate long-term debt. At December 31, 2007, approximately 90% (83% if we include the long-term debt subject to the fixed-to-floating interest rate swap as variable rate long-term debt) of our long-term debt, including fees and interest due for spent nuclear fuel disposal costs, is at a fixed interest rate. The remaining long-term debt is at variable interest rates and is subject to interest rate risk that could result in earnings volatility. Assuming a one percentage point increase in our variable interest rates, including the rate on long-term debt subject to the fixed-to-floating interest rate swap, annual interest expense would have increased by $3.7 million. At December 31, 2007, NU parent maintained a fixed-to-floating interest rate swap to manage the interest rate risk associated with its $263 million of fixed-rate long-term debt.

Credit Risk Management: Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of our contractual obligations. We serve a wide variety of customers and suppliers that include IPPs, industrial companies, gas and electric utilities, oil and gas producers, financial institutions, and other energy marketers. Margin accounts exist within this diverse group, and we realize interest receipts and payments related to balances outstanding in these margin accounts. This wide customer and supplier mix generates a need for a variety of contractual structures, products and terms which, in turn, require us to manage the portfolio of market risk inherent in those transactions in a manner consistent with the parameters established by our risk management process.

Credit risks and market risks at NU Enterprises are monitored regularly by a Risk Oversight Council. The Risk Oversight Council is comprised of individuals from outside of the management of these activities that create these risk exposures and functions to ensure compliance with our stated risk management policies.

We track and re-balance the risk in our portfolio in accordance with fair value and other risk management methodologies that utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

The New York Mercantile Exchange (NYMEX) traded futures and option contracts cleared off the NYMEX exchange are ultimately guaranteed by NYMEX to Select Energy. Select Energy has established written credit policies with regard to its counterparties to minimize overall credit risk on all types of transactions. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash in advance, letters of credit, and parent guarantees), and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in establishing credit limits prior to Select Energy entering into energy contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may impact Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes to economic, regulatory or other conditions.

At December 31, 2006, Select Energy maintained collateral balances from counterparties of $0.1 million. These amounts are included in current liabilities - other on the accompanying consolidated balance sheet. There were no such balances at December 31, 2007. Select Energy also has collateral balances deposited with counterparties of $18.9 million and $48.5 million at December 31, 2007 and 2006, respectively.

Our regulated companies have a lower level of credit risk related to providing regulated electric and gas distribution service than NU Enterprises. However, our regulated companies are subject to credit risk from certain long-term or high-volume supply contracts with

energy marketing companies. Our regulated companies manage the credit risk with these counterparties in accordance with established credit risk practices and maintain an oversight group that monitors contracting risks, including credit risk.

We have implemented an Enterprise Risk Management (ERM) methodology for identifying the principal risks of 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.

Additional quantitative and qualitative disclosures about market risk are set forth in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," contained within our 2007 Annual Report to Shareholders, which information is incorporated herein by reference.

Item 8. Financial Statements and Supplementary Data

NU. Reference is made to information under the headings "Report of Independent Registered Public Accounting Firm," "Consolidated Balance Sheets," "Consolidated Statements of Income/(Loss)," "Consolidated Statements of Comprehensive Income/(Loss)," "Consolidated Statements of Shareholders' Equity," "Consolidated Statements of Cash Flows," "Consolidated Statements of Capitalization," "Notes to Consolidated Financial Statements," and "Consolidated Statements of Quarterly Financial Data" contained within our 2007 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the headings "Report of Independent Registered Public Accounting Firm," "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Statements of Common Stockholder's Equity," "Consolidated Statements of Cash Flows," "Notes to Consolidated Financial Statements," and "Consolidated Quarterly Financial Data" contained within CL&P's 2007 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the headings "Report of Independent Registered Public Accounting Firm," "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Statements of Common Stockholder's Equity," "Consolidated Statements of Cash Flows," "Notes to Consolidated Financial Statements," and "Consolidated Quarterly Financial Data" contained within PSNH's 2007 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the headings "Report of Independent Registered Public Accounting Firm," "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Statements of Common Stockholder's Equity," "Consolidated Statements of Cash Flows," "Notes to Consolidated Financial Statements," and "Consolidated Quarterly Financial Data" contained within WMECO's 2007 Annual Report, which information is incorporated herein by reference.

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

No events that would be described in response to this item have occurred with respect to us, CL&P, PSNH or WMECO.

Item 9A. Controls and Procedures

We are responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements and other sections of this Annual Report on Form 10-K. NU's internal controls over financial reporting were audited by Deloitte & Touche LLP.

We are responsible for establishing and maintaining adequate internal controls over financial reporting. Our internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we 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, we concluded that our internal controls over financial reporting were effective as of December 31, 2007.

We, as well as CL&P, PSNH and WMECO, undertook separate evaluations of the design and operation of our disclosure controls and procedures to determine whether we are effective in ensuring that the disclosure of required information is made timely and in accordance with the Exchange Act and the rules and forms of the SEC. This evaluation was made under our supervision and with our participation, including our principal executive officers and principal financial officer, as of the end of the period covered by this Annual Report on Form 10-K. Our principal executive officers and principal financial officer have concluded, based on their review, that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in our reports that we file under the Exchange Act i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and ii) is accumulated and communicated to ou r management, including our principal executive officers and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no changes in internal controls over financial reporting for us, CL&P, PSNH and WMECO during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Item 9B. Other Information

No information is required to be disclosed under this item at December 31, 2007, as this information has been previously disclosed in applicable reports on Form 8-K during the fourth quarter of 2007.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information in Item 10 is provided as of February 26, 2008 except where otherwise indicated.

Certain information required by this Item 10 is omitted for PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly Owned Subsidiaries.

NU and CL&P

In addition to the information provided below concerning the executive officers of NU, incorporated herein by reference is the information contained in the sections captioned "Election of Trustees," "Governance of Northeast Utilities" and the related subsections, "Selection of Trustees," and "Section 16(a) Beneficial Ownership Reporting Compliance" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, expected to be dated March 31, 2008, which will be filed with the SEC pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

The names and ages of the executive officers of NU and the executive officers and Directors of CL&P, and the positions they hold, held, or have been elected to (as of February 26, 2008), and their business experience during the past five years, are set forth below.

Name	Age	Office and Business Experience During Past Five Years
Gregory B. Butler	50	**Senior Vice President and General Counsel** of NU since December 1, 2005 and of CL&P, PSNH and WMECO since March 9, 2006. Director of Northeast Utilities Foundation, Inc. since December 1, 2002. Previously, Senior Vice President, Secretary and General Counsel of NU from August 31, 2003 to December 1, 2005, and Vice President, Secretary and General Counsel of NU from May 1, 2001 through August 30, 2003.
Peter J. Clarke	46	**Vice President of Shared Services** of NUSCO, a subsidiary of NU, since January 1, 2008, and performs policy-making functions for NU and CL&P. Previously, Vice President - Customer Operations of CL&P and Yankee Gas from July 1, 2006 to December 31, 2007; Vice President - Customer Operations and Relations of CL&P from January 17, 2005 to June 30, 2006; and Director - System Projects of CL&P from March 11, 2002 to January 16, 2005.
Cheryl W. Grisé	55	**Executive Vice President** of NU from December 1, 2005 to July 1, 2007; Chief Executive Officer of CL&P from September 10, 2002 to January 15, 2007. Previously Chief Executive Officer of PSNH and WMECO from September 10, 2002 to January 15, 2007, a Director of CL&P from May 1, 2001 to January 15, 2007, of PSNH from May 14, 2001 to January 15, 2007 and of WMECO from June 2001 to January 15, 2007; previously President - Utility Group of NU from May 2001 to December 1, 2005.
Jean M. LaVecchia	56	**Vice President - Human Resources** of NUSCO, a subsidiary of NU, since June 30, 2005, and performs policy-making functions for NU and CL&P; also a Director of Northeast Utilities Foundation since January 30, 2007. Previously Vice President - Human Resources and Environmental Services from May 1, 2001 to June 30, 2005.
David R. McHale	47	**Senior Vice President and Chief Financial Officer** of NU, CL&P, PSNH and WMECO since January 1, 2005. Director of PSNH and WMECO since January 1, 2005 and CL&P since January 15, 2007. Director of Northeast Utilities Foundation since January 1, 2005. Previously Vice President and Treasurer of NU, WMECO and PSNH from July 1998 to December 31, 2004.
Raymond P. Necci*	56	**President and Chief Operating Officer and a Director** of CL&P and Yankee Gas since January 17, 2005. Director of Northeast Utilities Foundation since April 1, 2006. Previously, Vice President - Utility Group Services of NUSCO from January 1, 2002 to January 16, 2005.

Leon J. Olivier	59	**Executive Vice President-Operations** of NU since February 13, 2007, and Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007. Director of PSNH and WMECO since January 17, 2005 and a Director of CL&P since September 2001; also a Director of Northeast Utilities Foundation since April 1, 2006. Previously, Executive Vice President of NU from December 1, 2005 to February 13, 2007; President - Transmission Group of NU from January 17, 2005 to December 1, 2005, and President and Chief Operating Officer of CL&P from September 2001 to January 2005.
Shirley M. Payne	56	**Vice President - Accounting and Controller** of NU since February 13, 2007, and of CL&P, PSNH and WMECO since January 29, 2007. Previously, Vice President, Corporate Accounting and Tax of TECO Energy, Inc. from July 2000 to January 26, 2007 and Tax Officer of TECO Energy, Inc. from April 1999 to January 26, 2007.
James B. Robb	47	Senior Vice President, Enterprise Planning and Development, NUSCO since September 4, 2007, and performs policy-making functions for NU and CL&P. Previously, Managing Director, Russell Reynolds Associates from December 2006 to August 2007; Entrepreneur in Residence, Mohr Davidow Ventures from March 2006 to November 2006; Senior Vice President, Retail Marketing, Reliant Energy, Inc. from December 2003 to December 2006; Senior Vice President, Performance Management, Reliant Resources, Inc. from November 2002 to December 2003.
Charles W. Shivery	62	**Chairman of the Board, President and Chief Executive Officer** of NU since March 29, 2004 and Chairman and a Director of CL&P, PSNH and WMECO since January 19, 2007. Also a Director of Northeast Utilities Foundation since March 3, 2004. Previously, President (interim) of NU from January 1, 2004 to March 29, 2004; President – Competitive Group of NU and President and Chief Executive Officer of NU Enterprises, Inc., from June 2002 through December 2003.

* Executive Officer of CL&P only.

There are no family relationships between any director or executive officer and any other director or executive officer of NU and CL&P and none of the above Executive Officers or Directors serves as an Executive Officer or Director pursuant to any agreement or understanding with any other person. Our Executive Officers hold the offices set forth opposite their names until the next annual meeting of the Board of Trustees, in the case of NU, and the Board of Directors, in the case of CL&P, and until their successors have been elected and qualified.

CL&P obtains audit services from the independent registered public accounting firm engaged by the Audit Committee of NU's Board of Trustees. CL&P does not have its own audit committee or, accordingly, an audit committee financial expert.

CODE OF ETHICS AND STANDARDS OF BUSINESS CONDUCT

Each of NU, CL&P, PSNH and WMECO has adopted a Code of Ethics for Senior Financial Officers (Chief Executive Officer, Chief Financial Officer and Controller) and a Standards of Business Conduct which is applicable to all Directors, officers, employees, contractors and agents of NU, CL&P, PSNH and WMECO. The Code of Ethics and the Standards of Business Conduct have both been posted on the NU web site and are available at www.nu.com/investors/corporate_gov/default.asp on the Internet. Any amendments to or waivers from the Code of Ethics and Standards of Business Conduct will be posted on the website. Any such amendment or waiver would require the prior consent of the Board of Directors or an applicable committee thereof.

Printed copies of the Code of Ethics and the Standards of Business Conduct are also available to any shareholder without charge upon written request mailed to:

Ms. O. Kay Comendul
Assistant Secretary
Northeast Utilities Service Company
P.O. Box 270
Hartford, CT 06141

Item 11. Executive Compensation

NU

Incorporated herein by reference is certain information contained in the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, which is expected to be filed with the SEC on or about March 31, 2008. This information appears under the sections captioned "Compensation Discussion and Analysis" plus the related subsections, and "Compensation Committee Report" plus the related subsections.

CL&P

CL&P is a wholly-owned subsidiary of Northeast Utilities with a board of directors consisting entirely of executive officers of NU system companies. As such, CL&P does not have a compensation committee. NU's Compensation Committee of the Board of Trustees is responsible for compensation and benefits programs for the executive officers of CL&P. The compensation described for each executive officer in this Item 11 was for all services in all capacities to NU and its subsidiaries. All salaries, annual incentive amounts and long-term incentive amounts paid to these executive officers were paid by Northeast Utilities Service Company, a service company subsidiary of NU.

For purposes of this Item 11, references to "we," "our," and "us" refer to CL&P.

COMPENSATION DISCUSSION AND ANALYSIS

OVERALL OBJECTIVES OF EXECUTIVE COMPENSATION PROGRAM

The fundamental objective of the Executive Compensation Program for NU System companies is to motivate executives and key employees to support NU's strategy of investing in and operating businesses that benefit customers, employees, and shareholders. As a holding company for several regulated utilities, NU is also responsible to its franchise customers to provide energy services reliably, safely, with respect for the environment and its employees, and at a reasonable cost.

The Executive Compensation Program supports its fundamental objective through the following design principles:

- **Attract and retain key executives by providing total compensation competitive with that of other executives employed by companies of similar size and complexity.** The program relies on compensation data obtained from consultants' surveys of companies and from a customized peer group to ensure that compensation opportunities are competitive and capable of attracting and retaining executives with the experience and talent required to achieve our strategic objectives. As NU continues to grow and improve its transmission, distribution, and regulated generation systems, having the right talent will be critical.

- **Establish performance-based compensation that balances rewards for short-term and long-term business results.** The program motivates executives to run the business well in the short term, while executing the long-term business plan to benefit both NU's customers and shareholders. The program aims to strike a balance between the short- and long-term programs so that they work in tandem. It also ensures that long-term objectives are not sacrificed to achieve short-term goals or vice versa.

  Incentive plan performance criteria are based on a combination of financial, operational, stewardship, and strategic goals that are essential to the achievement of NU's business strategies. This linkage to critical goals helps to align executives with NU's key stakeholders—customers, employees, and shareholders. The long-term program also compares performance relative to a group of comparable utility companies.

- **Reward corporate and individual performance.** Overall compensation has many metrics based on corporate performance but is also highly differentiated based on individual performance. The annual incentive program rewards both team performance (measured by adjusted net income) and individual performance (including individualized financial, operational, stewardship and strategic metrics). Long-term incentives are composed of a performance cash program and restricted share units (RSUs). The performance cash program pays out based on the achievement of NU corporate goals (cumulative net income, average ROE, average credit rating and relative total shareholder return). The size of RSU grants reflects NU corporate performance during the preceding fiscal year as well as individual performance and contribution, but the ultimate value of the RSUs is based on NU's corporate total shareholder return.

- **Encourage long-term commitment to the company.** Utility companies provide a public service and have a long-term commitment to ensure that customers receive reliable service day after day. Meeting this commitment requires specialized skills and institutional knowledge that are learned over time through local industry experience. These skills include familiarity with the regions and communities that we serve, government regulations, and long-term energy policies. In addition, utility companies rely on long-term capital investments to serve their customers.

  As a result, public utilities benefit from long-service employees. NU has structured its executive compensation programs for the NU System Companies to build long-term commitment as well as shareholder alignment. Providing competitive compensation opportunities and offering programs such as RSUs and supplemental retirement benefits that vest and increase in value over time encourage long-term employment. Executive share ownership guidelines are another program component intended to build long-term shareholder alignment and commitment.

The executive officers listed in the Summary Compensation Table in this Annual Report on Form 10-K whose compensation is discussed in this CD&A are referred to as the "Named Executive Officers" or "NEOs." For 2007, CL&P's Named Executive Officers are:

- Charles W. Shivery, Chairman of the Board, President and Chief Executive Officer of NU; Chairman and a Director of CL&P
- David R. McHale, Senior Vice President and Chief Financial Officer of NU and CL&P; Director of CL&P
- Leon J. Olivier, Executive Vice President-Operations of NU; Chief Executive Officer and Director of CL&P
- Raymond P. Necci, President and Chief Operating Officer of CL&P and Yankee Gas
- Gregory B. Butler, Senior Vice President and General Counsel of NU and CL&P
- Cheryl W. Grisé, Chief Executive Officer of CL&P through January 15, 2007; Executive Vice President of NU through July 1, 2007

ELEMENTS OF 2007 COMPENSATION

Set forth below is a brief description and the objective of each material element and the additional benefits of NU's executive compensation program:

Compensation Element	Description	Objective
Base Salary	Fixed compensation Usually increased annually during the first quarter based on individual performance, competitive market levels, strategic importance of the role and experience in the position	Compensate officers for fulfilling their basic job responsibilities Provide base pay commensurate with the median salaries paid to executive officers holding comparable positions in other utility companies and companies in general industry Aid in attracting and retaining qualified personnel
Annual Incentive Program	Variable compensation based on performance against pre-established annual team and individual goals that is paid in cash in the first quarter following the end of the program year	Promote the achievement of annual performance objectives that represent business success for the company, the executive, and his or her business unit or function
Long-Term Incentive Program	Variable compensation consisting of one-half RSUs and one-half performance cash (see below)	
· Restricted share units (RSUs)	NU common share units, which vest over a three-year period, granted based on corporate performance and individual performance and contribution	Align executive and shareholder interests through share performance and share ownership Encourage a long-term commitment to the company
· Performance Cash Program	Long-term cash incentive that rewards individuals for NU corporate performance over a three-year period based on achieving pre-established levels of: · Cumulative net income · Average ROE · Average credit rating · Total shareholder return relative to a group of comparable utility companies	Reward performance on key corporate priorities that are also key drivers of total shareholder return performance Encourage long-term thinking and commitment to the company
Supplemental Benefits	Supplemental Executive Retirement Plan (SERP), Nonqualified Deferred Compensation, and Perquisites	Supplemental benefits intended to help NU attract and retain executive officers critical to its success by reflecting competitive practices

· Supplemental Executive Retirement Plan (Supplemental Plan)	Non-qualified pension plan, providing additional retirement income to officers beyond payments provided in NU's standard defined benefit retirement plan, consisting of: · A defined benefit "make-whole" plan. · A supplemental "target" benefit (certain senior vice presidents and above only) · Exempt employees, including executives, hired after 2005 are ineligible for these benefits	Compensate for Internal Revenue Code limits on qualified plans Aid in retention of executives and enhance long-term commitment to the company
· Other Nonqualified Deferred Compensation (Deferral Plan)	Opportunity to defer base salary and annual incentives, using the same investment vehicles as the NU qualified 401(k) plan, and receive matching contributions otherwise capped by Internal Revenue Code limits on qualified plans Each year's match vests after three years or at retirement For executives hired after 2005 who are ineligible to participate in NU's defined benefit pension plan, NU makes contributions of 2.5%, 4.5% and 6.5%, as applicable based on the relevant bracket for the sum of the officer's age and years of service, on cash compensation that would otherwise be capped by Internal Revenue Code limits on qualified plans	Aid executives in tax planning by allowing them to defer taxes on certain compensation Compensate for Internal Revenue Code limits on qualified plans Provide a competitive benefit Aid in retention and enhance long-term commitment to the Company
· Perquisites	Financial planning and tax preparation reimbursement benefit Executive physical examination reimbursement plan Other perquisites including reimbursement of spousal travel expenses for business purposes	Encourage use of a professional to prepare tax returns and maximize value of compensation Encourage executives to undergo regular health checks to reduce the risk of losing critical employees Discretionary benefits intended to help executive officers be more productive and efficient
Employment Agreements	Employment agreements with certain of our Named Executive Officers provide benefits and payments upon involuntary termination and termination following a change of control. Mr. Olivier and Mr. Necci participate in a "Special Severance Program" that provides other benefits and payments upon termination of employment resulting from a change-in-control	Meet competitive expectation of employment Help focus executive on shareholder interests Provide income protection in the event of involuntary loss of employment

MIX OF COMPENSATION ELEMENTS

NU strives to provide executive officers of its system companies with base salary, annual incentive compensation and long-term incentive compensation opportunities based on performance at or above the market median over time. NU establishes the market median as described under the caption entitled Market Analysis, below. As a result, the annual and long-term incentive target percentages for the Named Executive Officers are approximately equal to competitive median incentives.

With respect to incentive compensation, the Compensation Committee believes it is important to balance short-term goals, such as generating earnings per share, with longer term goals, such as long-term value creation and maintaining a strong balance sheet. As the executive officers are promoted to more senior positions, they assume increased responsibility for implementing the company's long-term business plans and strategies, and a greater proportion of their total compensation is based on performance with a long-term focus. Historically, long-term incentive compensation has been weighted more significantly than short-term incentives at target, reflecting the longer-term nature of our business plans. Accordingly, as depicted in the table below, the long-term incentive compensation targets of each of the NEOs, as percentages of base salary, are slightly higher than the median targets reflected in the utility and general industry survey data that we use to analyze exec utive compensation. As a result, short-term incentive compensation is generally lower. The survey data for long-term incentive compensation is based on the present value of actual long-term incentive grants. We discuss this survey data in greater detail below under the caption entitled Market Analysis.

The Compensation Committee determines total compensation for each executive officer based on the relative authority, duties and responsibilities of each office within the NU system. Mr. Shivery's responsibilities, as Chairman, President and Chief Executive Officer of NU, for the daily operations and management of the NU System companies are significantly greater than the duties and responsibilities of our other executive officers. As a result, our Mr. Shivery's compensation is significantly higher than the compensation of our other executive officers. The Compensation Committee regularly reviews market compensation data for executive officer positions similar to those held by our executive officers, including Mr. Shivery, and this market data continues to indicate that chief executive officers are typically paid significantly more than other executive officers. For 2007, target annual incentive and long-term incentive compensation opportunities for Mr. Shivery we re 100% and 300% of base salary, respectively. For the remaining NEOs, target annual incentive compensation opportunities ranged from 50% to 65% of base salary and target long-term incentive compensation opportunities ranged from 85% to 150% of base salary. Mr. Olivier's long-term incentive compensation target was fixed at 125% of his base salary, which is below a target of 150% of base salary typically provided to executive officers at his level, because his total compensation includes a special retirement benefit. Mrs. Grisé, who resigned as chief executive officer of CL&P effective January 15, 2007 and retired from NU effective July 1, 2007, did not participate in the 2007 – 2009 Long-Term Incentive Program.

The following table sets forth the contribution to 2007 Total Direct Compensation (TDC) of each element of compensation, at target, reflected as a percentage of TDC, for each Named Executive Officer. Annual incentive awards and performance cash awards under the long-term incentive program were performance based and, accordingly, were at risk.

	Percentage of (TDC) at Target				
		Performance Based (1)			
			Long-Term Incentives (2)		
Named Executive Officer	Base Salary	Annual Incentive	Performance Cash	RSUs (3)	TDC
Charles W. Shivery	20%	20%	30%	30%	100%
David R. McHale	32%	20%	24%	24%	100%
Leon J. Olivier	34%	22%	22%	22%	100%
Raymond P. Necci	43%	21%	18%	18%	100%
Gregory B. Butler	32%	20%	24%	24%	100%
Cheryl W. Grisé (4)	61%	39%	--%	--%	100%

(1) The annual incentive compensation element and the long-term incentive compensation element are performance-based.
(2) Long-term incentive compensation at target consists of equal proportions of performance cash awards and RSUs.
(3) RSUs are granted based on annual NU corporate and individual performance, but vest over three years contingent upon continued employment. The percentages reflect the target value of the RSUs on the date of grant.
(4) Mrs. Grisé resigned as chief executive officer of CL&P effective January 15, 2007 and retired from NU effective July 1, 2007.

MARKET ANALYSIS

The Compensation Committee strives to provide our executive officers with compensation opportunities over time at or above the median compensation levels for executive officers of companies comparable to us. The Committee determined executive officer TDC levels in two steps. First, the Committee determined the "market" values of executive officer compensation elements (*e.g.*, base salaries, annual incentives and long-term incentives) as well as total compensation using compensation data obtained from other companies. Th1e Committee reviewed compensation data obtained from two sources: (i) utility and general industry survey data and (ii) customized peer group data. The Committee then reviewed the compensation elements for each executive officer with respect to the median of these market values, and considered individual performance, experience and internal pay equity to determine the amount, if any, by which the various compensation elements should exceed t he median market values. Significantly, the Committee has not made a commitment to compensate our executive officers through a firm and direct connection between the compensation paid by us and the compensation paid by any of the companies from which the utility and general industry survey data and the customized peer group data was obtained.

Set forth below is a description of the sources of the compensation data used by the Compensation Committee:

- **Utility and general industry survey data**. The Committee analyzed compensation information obtained from surveys of diverse groups of utility and general industry companies that represent our market for executive officer talent. The Committee used the utility and general industry survey data to determine base salaries and incentive opportunities. The compensation consultant reviewed subsets of survey data applicable to utility companies correlated to reflect entities similar in size to us. Then the Committee compared utility-specific executive officer positions, including Mr. Olivier, who serves as NU's Executive Vice President – Operations as well as CL&P's Chief Executive Officer, to utility-specific market values. For executive officer positions that have counterparts in general industry, including NU's Chief Executive Officer; Senior Vice President and Chief Financial Officer; and Senior Vice President and General Counse l, the Committee averaged general industry comparisons with utility industry comparisons weighted equally.

- **Customized peer group data.** The Committee also evaluated compensation data obtained from reviews of proxy statements from a customized group of peer utility companies consisting of: (i) utilities that are substantially regulated with annual revenues that ranged from $2.5 billion to $12 billion with median annual revenues of $5.6 billion; and (ii) utilities that are less regulated and closer in size to NU, with annual revenues that ranged from $3 billion to $7 billion. Although we do not consider utilities that are less regulated to be direct performance peers, these companies represent potential sources of talent. The Committee considered data only for those executive officer positions where there is a title match. For 2007, this group consisted of the following 22 companies:

Allegheny Energy, Inc.	Great Plains Energy Incorporated	PPL Corporation
Alliant Energy Corporation	NiSource Inc.	Progress Energy, Inc.
Ameren Corporation	NSTAR	Puget Energy, Inc.
CenterPoint Energy, Inc.	OGE Energy Corp.	SCANA Corporation
CMS Energy Corporation	PG&E Corporation	Sierra Pacific Resources
Consolidated Edison, Inc.	Pepco Holdings, Inc.	TECO Energy, Inc.
Energy East Corporation	Pinnacle West Capital Corporation	Wisconsin Energy Corporation
		Xcel Energy Inc.

The Committee used compensation data obtained from these companies for insights into incentive compensation design practices and compensation levels, although no specific actions were taken in 2007 directly as a result of this data. In 2007, the Committee also used a subset of this group for performance comparisons under the performance cash program as described below under the caption entitled 2007 – 2009 Long-Term Incentive Program. The Committee periodically adjusts the target percentages of annual and long-term incentives based on the survey data to ensure that they continue to represent market median levels. Adjustments are made gradually over time to avoid radical changes.

The Compensation Committee also sets supplemental benefits at levels that provide market-based compensation opportunities to the executive officers. Compensation includes perquisites to the extent they serve business purposes. The Committee periodically reviews the general market for supplemental benefits and perquisites using utility and general industry survey data, sometimes including data obtained from companies in the customized peer group. Benefits are adjusted occasionally to maintain market parity. When the market trend for supplemental benefits reflects a general reduction, (*e.g.*, the elimination of defined benefit pension plans), the Committee has reduced these benefits only for newly hired officers. The Committee reviewed NU's supplemental retirement practices most recently in 2005 and 2006, as described in more detail below under the caption entitled Supplemental Benefits.

BASE SALARY

The Compensation Committee reviews executive officers' base salaries annually. The Committee considers the following specific factors when setting or adjusting base salaries:

- Annual individual performance appraisals
- Market pay movement across industries (determined through market analysis)
- Targeted market pay positioning for each executive officer
- Individual experience and years of service
- Changes in corporate focus with respect to strategic importance of a position
- Internal equity

Individuals who are performing well in strategic positions are likely to have their base salaries increased more significantly than other individuals. From time-to-time, weak corporate performance has caused salary increases to be postponed, but the Committee prefers to reflect subpar corporate performance through the variable pay components.

Based on these considerations, the Compensation Committee acting jointly with the Corporate Governance Committee recommended to NU's Board of Trustees a salary increase for Mr. Shivery of 6.4%, which was approved by the Board of Trustees. Mr. Shivery's base salary was increased to the competitive median to recognize his level of contribution in his role as Chief Executive Officer of NU. The Compensation Committee also approved base salary increases in 2007 as follows: Mr. McHale: 20.0%; Mr. Olivier: 14.7%; Mr. Necci: 5.0%; and Mr. Butler: 7.0%. The Compensation Committee approved more significant base salary increases for Messrs. Olivier and McHale so that the base salary of each of them approached the median base salary for their respective positions. Mr. Olivier's salary increase was primarily related to his promotion to Executive Vice President - Operations of NU in early 2007. Mr . McHale's salary increase was primarily based on his increased experience and individual performance during 2006. Mr. Necci's increase brought his base salary closer to median, and Mr. Butler's increase recognized increasing competitive pay levels for top legal professionals and his responsibilities in addition to oversight of the legal function. Mrs. Grisé did not receive a base salary increase for 2007 because she had previously announced her plans to retire in 2007.

INCENTIVE COMPENSATION

The annual incentive program and the long-term incentive program are provided under the Northeast Utilities Incentive Plan, which was approved by NU's shareholders at NU's 2007 Annual Meeting of Shareholders. The annual incentive program provides cash compensation intended to reward performance under our annual operating plans. The long-term incentive program is designed to reward demonstrated performance and leadership, motivate future superior performance, align the interests of the executive officers with those of our shareholders and retain the executive officers during the term of awards. Awards under the long-term incentive program consist of two elements of compensation, RSUs and performance cash. The Compensation Committee selected RSUs as the equity component of long-term awards because utility companies create value for shareholders through the payment of periodic dividends as well as through share price appreciation. The a nnual and long-term programs are intended to work in tandem so that achievement of our annual goals leads us towards attainment of our long-term financial goals.

Incentive awards are based on objective financial performance goals established by the Compensation Committee with the advice of the Finance Committee. The Compensation Committee sets the performance goals annually for new annual incentive and long-term incentive program performance periods, depending on NU's business focus for the then-current year and the long-term strategic plan. The Compensation Committee has modified the performance goals more significantly in recent years in connection with NU's increased focus on its regulated utility businesses.

2007 ANNUAL INCENTIVE PROGRAM

The 2007 Annual Incentive Program consisted of a team goal plus individual goals for each NEO. The Compensation Committee set the annual incentive compensation targets for 2007 at 100% of base salary for Mr. Shivery and at 50% to 65% of base salary for the other NEOs. The annual incentive compensation targets are used as guidelines for the determination of annual incentive payments, but actual annual incentive payments may vary significantly from these targets, depending on individual and corporate performance. Actual annual incentive payments may equal up to two times target if NU achieves superior financial and operational results. The opportunity to earn up to two times the incentive target reflects the Compensation Committee's belief that executive officers have significant ability to affect performance outcomes. However, NU does not pay annual incentive awards if minimum levels of financial performance are not met.

If NU's earnings were to be restated as a result of noncompliance with accounting rules caused by fraud or misconduct, the Sarbanes-Oxley Act of 2002 would require Mr. Shivery and our Chief Financial Officer to reimburse NU for certain incentive compensation received by each of them. To the extent that reimbursement were not required under Sarbanes-Oxley, NU's Incentive Plan would require any employee whose misconduct or fraud caused such restatement, as determined by NU's Board of Trustees, to reimburse NU for any incentive compensation received by him or her. To date, there have been no restatements to which either the Sarbanes-Oxley reimbursement provisions or the Incentive Plan reimbursement provisions would apply.

2007 Team Goal

The objective of the 2007 Annual Incentive Program team goal for the NEOs was to achieve an adjusted net income for NU (ANI) target established by the Compensation Committee. ANI is defined as consolidated NU net income adjusted to exclude the effect of certain nonrecurring income and expense items or events. The Committee uses ANI because it believes that ANI serves as an indicator of ongoing operating performance. The minimum payout under the team goal was set at 50% of target and would occur if actual ANI was at least 90% of the ANI target. The maximum payout under the team goal was set at 200% of target and would occur if actual ANI was at least 10% above the ANI target. We would pay annual incentive compensation related to individual goals only if actual ANI was at least 80% of the ANI target.

For 2007, the Compensation Committee established the ANI target at $219.4 million. The ANI target reflects the midpoint of the range of internal ANI estimates calculated at the beginning of the year. The ANI thresholds for the individual and team goals appear below (dollars in millions):

Threshold For Individual Goals (20% below ANI Goal)	Minimum Team Goal (10% below ANI Goal)	2007 ANI Goal	Maximum Team Goal (10% above ANI Goal)	Actual 2007 ANI
$175.5	$197.5	$219.4	$241.3	$257.9

The Compensation Committee set the ANI threshold for achieving individual goals and the minimum and maximum team goals in its discretion based on the following factors:

- An assessment of the potential volatility in results;
- The degree of difficulty in achieving the ANI target; and
- The minimum acceptable ANI.

At the time that the Compensation Committee established the performance goals for 2007, the Committee also considered and agreed upon exclusions from ANI consisting of certain nonrecurring income and expense items or events that were either beyond the control of management generally or related to a decision by the Committee not to penalize executive officers for making correct strategic business decisions. The number of exclusions reflects the complexity of NU's business as it continues to increase its focus on its regulated utility businesses. The Compensation Committee approved all final exclusions from ANI. In 2007, the income and expense items set forth below were excluded from ANI in 2007. The Net Adjustments to ANI did not impact the achievement of the maximum team goal.

Excludable Categories	Specific 2007 Adjustments ($ in millions)
Changes to net income as the result of accounting or tax law changes	$ (12.8)
Unexpected costs relating to nuclear decommissioning	1.4
Unexpected costs related to environmental remediation at Holyoke Water Power Company	--
Unbudgeted charitable contributions	(1.8)
Impairments on goodwill acquired before 2002 (more than five years prior to the beginning of this program period)	--
Changes to net income resulting from any settlement of, or final decision in, ongoing litigation with Consolidated Edison	--
Mark-to-market impacts of agreements to which NU or any of NU competitive subsidiaries are parties	(3.8)
Unusual IRS/regulatory decisions	--
Divestiture or discontinuance of a significant segment or component of NU's competitive businesses	(2.4)
Net benefit to income from customer service integration project delay *	6.4
Net Adjustments:	**$ (13.0)**

* Excluded from ANI at the discretion of the Compensation Committee.

2007 Individual Goals

The 2007 Annual Incentive Program individual goals included various financial, operational, stewardship, and strategic metrics that are drivers of overall corporate performance. The achievement of individual goals would result in an annual incentive payment only if actual ANI is at least 80% of the ANI target. This ANI threshold satisfies the requirements of Section 162(m) of the Internal Revenue Code. Upon achieving this ANI threshold, the maximum payout is possible for individual goals for every participant.

The Committee acts in its discretion under Section 162(m) and related Internal Revenue Service (IRS) rules and regulations to ensure that incentive compensation payments are "qualified performance based compensation" not subject to the $1 million limitation on deductibility. The Compensation Committee, acting jointly with the Corporate Governance Committee, determines Mr. Shivery's proposed annual incentive program payment based on the extent to which individual and NU corporate goals have been achieved. The Compensation Committee recommends to the Board of Trustees for approval the proposed award for Mr. Shivery. For the remaining

NEOs, Mr. Shivery recommends annual incentive awards to the Compensation Committee for its approval. NEOs are eligible to receive up to two times the annual incentive compensation target for the individual portion of the award.

Goal Weightings for 2007

The following table sets forth the weighting of the annual incentive program team goal and individual goals of each NEO's compensation for 2007. These weightings reflect the Compensation Committee's desire to balance individual accountability with teamwork across the organization. Individual goals collectively range from 40% to 70% of the total annual incentive program target. Certain of our NEO's individual performance goals are subjective in nature and cannot be measured either by reference to existing financial metrics or by using pre-determined mathematical formulas. The Committee believes that it is important to exercise judgment and discretion when determining the extent to which each NEO satisfies subjective individual performance goals. The Committee considers these goals along with several factors, including overall individual performance, corporate performance, prior year compensation and the other factors discussed be low.

Name and Principal Position	Team Goal Weighting	Individual Goal Weighting	Brief Description of Material Individual Goals
Charles W. Shivery Chairman of the Board, President, and Chief Executive Officer of NU; Chairman of CL&P	60%	40%	Ensure effective execution of the company's strategic plan and the operating and capital plans (30% of individual goals). Achieve successful outcomes in federal and state energy regulatory policy and ratemaking proceedings; develop comprehensive communications strategy regarding critical issues (20% of individual goals). Achieve progress in continued development and implementation of energy policy in New England (20% of individual goals). Implement strategic planning organization to create decision making framework to evaluate strategic options available to the company (15% of individual goals). Focus on workforce management and effective pay for performance; meet company objectives for safety, diversity and the environment (15% of individual goals).
David R. McHale Senior Vice President and Chief Financial Officer	60%	40%	Strategic initiatives: Operational planning, risk management, and capital allocation (25% of individual goals). Business execution: Lead efforts in rate cases, regulatory strategy, energy policy, and corporate cost analysis and management (40% of individual goals). Financial organization: Reorganize corporate finance function and related financial improvement initiatives (20% of individual goals). Competitive business divestiture (15% of individual goals).

Leon J. Olivier Executive Vice President - Operations of NU; Chief Executive Officer of CL&P	40%	60%	Manage the capital program budget (45% of individual goals). Achieve significant progress in New England East-West Solution, a joint project with National Grid designed to improve reliability and electric transfer capability in Springfield, Massachusetts and central and northeast Connecticut (15% of individual goals). Achieve successful outcomes in federal and state energy regulatory policy and ratemaking proceedings (20% of individual goals). Fully integrate new computer system for managing work requests, design, scheduling, construction and closeout processes (10% of individual goals). Comply with federal and state energy regulatory requirements (10% of individual goals).
Raymond P. Necci President and Chief Operating Officer of CL&P and Yankee Gas	30%	70%	Achieve Net Income goals for CL&P and Yankee Gas (20% of individual goals). Achieve a resolution of CL&P and Yankee Gas delivery rate cases that reasonably support operational and financial objectives (20% of individual goal). Complete all key project category milestones associated with the LNG project on schedule and within budget (10% of individual goal). Improve reliability performance of CL&P and Yankee Gas (20% of individual goals). Achieve CL&P and Yankee Gas safety performance (20% of individual goal). Implement a comprehensive self assessment program to identify and correct procedure compliance weaknesses (10% of individual goal).
Gregory B. Butler Senior Vice President and General Counsel	50%	50%	Achieve successful outcomes in federal and state energy regulatory policy and ratemaking proceedings (40% of individual goals). Manage his areas of responsibility (45% of individual goals). Position NU to assume a leadership role in state and federal regulatory matters; develop and implement New England energy policy (15% of individual goals).
Cheryl W. Grisé Former Chief Executive Officer	40%	60%	Effectively transition from active role in management to advisory role in anticipation of retirement (100% of individual goals).

2007 Results

The 2007 actual ANI was $257.9 million, which exceeded the maximum ANI amount for annual program team goal. As a result, a portion of the total annual incentive payment to each NEO was attributable to achieving the maximum team goal. In addition, the 2007 actual ANI also exceeded the individual goal threshold. Accordingly, the balance of the annual incentive payment to each NEO was based on the extent to which each NEO achieved his or her individual goals.

Annual Incentive Payment for Mr. Shivery

The Compensation Committee and the Corporate Governance Committee assessed Mr. Shivery's performance on his individual goals described in the table above. Set forth below is a description of the Committees' assessment of Mr. Shivery's performance against these goals:

Mr. Shivery's execution of NU's long-term strategic plan as well as its operating and capital plans was above expectations. In the aggregate, major transmission projects were on or ahead of schedule and at or below budget. Implementation of the $6 billion capital investment program is on track and has yielded increased earnings and improved reliability. In 2007, NU's transmission business very successfully completed a compliance audit by the North Atlantic Electric Reliability Corporation.

Overall customer satisfaction ratings improved for all but one business unit.

On balance, Mr. Shivery met expectations relative to rate-making and regulatory policy proceedings. Rate cases for PSNH and Yankee Gas were settled without significant issues, and the settlements allowed both entities to meet their respective financial objectives. However, the disappointing outcome of the CL&P rate case was below our range of expected results. In addition, CL&P was challenged during the year with poor responsiveness to customers' concerns and issues. Senior management has since taken this issue as an opportunity to solidify NU's commitment to meet its customers' expectations. Under Mr. Shivery's direction, management developed and implemented a multi-year communications strategy designed to communicate critical issues.

Mr. Shivery exceeded expectations with respect to NU's New England energy policy initiatives. NU is actively involved in addressing regional energy reliability and environmental issues through Mr. Shivery's initiative and is making outstanding contributions in this area. In addition, we have advanced the discussion regarding pursuit of potential energy solutions outside of NU's geographical region with industry leaders and policymakers. Mr. Shivery also co-chairs the Edison Electricity Institute (EEI) Energy Delivery Committee, which has helped frame EEI positions around critical energy policy issues on a national and regional level.

Mr. Shivery met expectations relative to developing a longer-term strategic plan. He and his management team have identified emerging strategic opportunities which they are pursuing and have expanded their attention to enterprise risk management. In the third quarter, Mr. Shivery successfully hired a new officer as Senior Vice President – Enterprise Planning to further develop NU's thinking about its future positioning and strategic opportunities.

Mr. Shivery continued to emphasize aligning the culture of the company to assure support of its strategic direction, performing above expectations in this goal area. Under Mr. Shivery's direction, workforce plans were completed throughout the company and initiatives were implemented to address critical needs, including the introduction of business, financial and technical educational opportunities for NU employees. Mr. Shivery and the management team continued to improve safety, enhance diversity and effectively manage NU's environmental responsibilities.

The Compensation Committee and the Corporate Governance Committee of NU's Board of Trustees jointly considered Mr. Shivery's performance on all of the individual performance goals set forth above. Coupled with NU's overall corporate performance measured by ANI, the committee members applied judgment to determine their recommendation for Mr. Shivery's annual incentive payment. In particular, the committees gave weight to the finding that NU's total shareholder return in 2007 was in the top quartile of NU's performance peer group of companies. Following a detailed review of these factors without Mr. Shivery present, the Board of Trustees awarded Mr. Shivery an annual incentive payment of $1,683,360 for 2007, consisting of $1,184,770 attributable to the achievement of 200% of the team goal and an additional $498,590 attributable to Mr. Shivery's performance of his individual goals. The Board o f Trustees determined that this annual incentive payment was consistent with Mr. Shivery's above-expectations performance based on corporate, financial and individual criteria established for 2007. This amount also reflected an increase from the annual incentive payment received by Mr. Shivery for 2006, which the Board of Trustees believed was warranted in light of NU's sustained strong corporate performance in 2007. Mr. Shivery's annual incentive payment exceeds that of the other NEOs because of his significantly greater duties and responsibilities as NU's chief executive officer.

Annual Incentive Payment for the Other NEOs

In addition to NU's corporate ANI goal described above, the Compensation Committee considered individual performance goals and other factors in determining the annual incentive payments for each of the other NEOs. These factors included the annual incentive payment recommendations made by Mr. Shivery with respect to each of the NEOs and the scope of each NEO's responsibilities, performance, and impact on or contribution to our corporate success and growth. The annual incentives paid to each NEO as described below include the maximum amount for the corporate ANI goal component.

The Compensation Committee determined that Mr. McHale and his organization made significant advancements strengthening NU's enterprise risk management and financial organization capabilities and processes. Mr. McHale and his team successfully completed NU's capital financing objectives for 2007 despite a difficult fixed-income market in the second half of the year, and maintained the current credit ratings and rating agency outlooks on NU and its four regulated utilities, despite increased capital expenditure projections. In addition, Mr. McHale's organization played a critical role in rate cases for three of NU's business units that, in the aggregate, produced results that were within NU's anticipated range although the outcome of the CL&P rate case was below our range of expected results. Finally, Mr. McHale and his team were successful at reducing the market risk of NU's competitive businesses while achieving above-bud get net income. Based on his demonstrated leadership and this assessment of his successes, the Compensation Committee awarded Mr. McHale an annual incentive payment of $487,620 for 2007.

The Compensation Committee determined that Mr. Olivier and his team successfully completed important LNG storage, electric distribution, and electric transmission system projects and have made excellent progress on the New England East West Solution (NEEWS) major electric transmission system project. These projects will help position NU for the future and bring significant benefits to both customers and shareholders. In addition, Mr. Olivier's team has improved system reliability. In 2007, NU's transmission business very successfully completed a compliance audit conducted by the North American Electric Reliability Corporation. Based on his demonstrated leadership and this assessment of his successes, but acknowledging his shared responsibility for the CL&P rate case and customer service issues cited in the preceding description of Mr. Shivery's award, the Compensation Committee awarded Mr. Olivier an annual incentive pay ment of $452,226 for 2007.

The Compensation Committee determined that Mr. Butler's team advanced NU's position on regional energy policy considerably in Connecticut, Massachusetts and New Hampshire, which will ultimately provide benefits to customers and shareholders. In addition, Mr. Butler's team successfully communicated the need for additional revenues for three of NU's companies, each of which conducted state regulatory ratemaking proceedings in 2007, although the outcome of the CL&P rate case was below NU's range of expected results. Based upon these successes, but acknowledging his shared responsibility for the CL&P rate case and customer service issues cited in the preceding description of Mr. Shivery's award, the Compensation Committee awarded Mr. Butler an annual incentive payment of $390,700 for 2007.

The Compensation Committee determined that Mr. Necci and his team improved system reliability and successfully completed important LNG storage and electric distribution system projects, which help position us for the future and bring significant benefits to both customers and shareholders. Based on his demonstrated leadership and this assessment of his successes, but acknowledging his shared responsibility for the CL&P rate case and customer service issues cited in the preceding description of Mr. Shivery's award, the Compensation Committee awarded Mr. Necci an annual incentive payment of $208,660 for 2007.

Although Mrs. Grisé retired from NU during 2007, she was eligible to receive a prorated annual incentive payment for 2007. The Compensation Committee determined that Mrs. Grisé was successful in assisting NU in preparing for an orderly transition following her retirement and awarded Mrs. Grisé an annual incentive payment of $187,645 for 2007, representing an overall payout at target when adjusted for her term of employment during 2007.

2007 – 2009 LONG-TERM INCENTIVE PROGRAM

The Compensation Committee, acting jointly with the Corporate Governance Committee recommended to NU's Board of Trustees a long-term incentive target grant value for Mr. Shivery as a percentage of base salary on the date of grant, which recommendation was approved by NU's Board of Trustees. The Compensation Committee also approved long-term incentive target grant values for each of the other NEOs as a percentage of base salary on the date of grant. At target, each grant consisted of one-half RSUs and one-half performance cash, subject to adjustment by the Compensation Committee (except the Compensation Committee acts jointly with the Corporate Governance Committee in recommending to NU's Board of Trustees adjustments to Mr. Shivery's targets), reflecting the Committee's desire to balance total shareholder return with NU's corporate financial performance. In 2007, the Compensation Committee, acting jointly with the Corporate Governa nce Committee, recommended to NU's Board of Trustees a long-term incentive compensation target for Mr. Shivery at 300% of base salary, which NU's Board of Trustees approved. The Compensation Committee established long-term incentive compensation targets at 85% to 150% of base salary for the remaining NEOs. Mr. Olivier's long-term incentive compensation target was

fixed at 125% of his base salary, which is below a target of 150% of base salary typically provided to executive officers at his level, because his compensation includes a special retirement benefit. Mrs. Grisé, who resigned as chief executive officer of CL&P effective January 15, 2007 and retired from NU effective July 1, 2007, did not participate in the 2007 – 2009 Long-Term Incentive Program.

Restricted Share Units (RSUs)

Each RSU awarded under the long-term incentive program entitles the holder to receive one NU common share at the time of vesting. All RSUs awarded in 2007 will vest in equal annual installments over three years. RSU holders are eligible to receive dividend equivalents on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU's common shares. Dividend equivalents are accounted for as additional common shares that accrue and are distributed simultaneously with the common shares issued upon vesting of the underlying RSUs.

At the beginning of each year, the Compensation Committee determines target RSU awards for each participant in the long-term incentive program. Initially, the target RSU awards are equal to one-half of the long-term incentive compensation target for each participant. RSU awards are based on a percentage of base salary and measured in dollars. The aggregate dollar amount of the target RSU awards for all participants constitutes the target RSU Pool for that particular long-term incentive program. The Committee reserves the right to increase or decrease the target RSU Pool based on NU's financial performance during the preceding fiscal year. In its discretion, the Committee may also increase or decrease RSU awards for individual participants based on the contribution by the executive officer to NU's long-term strategic direction and the Committee's assessment of the need to motivate the executive officer's future performance. The Compensation Committee, acting jointly with the Corporate Governance Committee, recommends to NU's Board of Trustees the final RSU award for Mr. Shivery. Based on input from Mr. Shivery, the Compensation Committee determines the final RSU awards for each of the other NEOs. Increases or decreases to target RSU awards for our executive officers will increase or decrease their compensation as compared to the compensation of executive officers of utilities listed in our customized peer group. Increases or decreases to individual target RSU awards will also correspondingly increase or decrease the RSU pool.

All RSUs are granted on the date of the Committee meeting at which they are approved. RSU grants are subsequently converted from dollars into NU common share equivalents by dividing the amount of each award by the average closing price for NU common shares during the last ten trading days in January in the year of the grant.

In 2007, the Committee approved a final RSU Pool for executive officers of NU System Companies, consisting of $5,340,525, which represents 146.5% of target, based on NU's corporate performance during 2006 in connection with the increased focus on NU's regulated utility businesses. The following RSU awards were approved, reflected as a percentage of target and in dollars, based on individual performance and contributions: Mr. Shivery: 175% ($2,625,000); Mr. McHale: 150% ($506,250); Mr. Olivier: 150% ($445,313); Mr. Necci: 110% ($139,715) and Mr. Butler: 130% ($377,918). The Committee did not grant RSU awards under the long-term incentive program to Mrs. Grisé, who retired from NU effective July 1, 2007.

RSU Design Changes

RSUs granted under the 2004 long-term incentive compensation program vest in equal installments on the grant-date anniversaries over four years. All RSUs granted under the 2005 and 2006 long-term incentive compensation programs vest in equal installments on the grant-date anniversaries over three years. Pursuant to the terms of the original RSU awards (except with respect to certain RSUs granted to Mr. Shivery), on each vesting date, NU distributed common shares to the RSU holders only with respect to one-half of the number of RSUs that vested. NU deferred the distribution of the remaining one-half of the common shares for an additional four years. Because RSU holders are taxed only upon the receipt of the underlying common shares, taxes on such remaining one-half of the common shares were also deferred for an additional four years. Pursuant to an agreement with Mr. Shivery, NU continues to defer the distribution of common shares upon the vest ing of RSUs granted to him under the 2005, 2006 and 2007 programs until after he leaves NU. Except for RSUs granted to Mr. Shivery, the 2007 long-term incentive program did not contain automatic deferred distribution provisions.

In 2007, consistent with the adoption of share ownership guidelines (discussed below), the Compensation Committee amended the 2004, 2005 and 2006 long-term incentive compensation programs to eliminate the deferred distribution feature for executive officers, except for RSUs granted to Mr. Shivery under the 2004 program. The Committee also permitted executive officers to elect to continue deferred distribution of common shares upon vesting of RSUs granted under these programs. Executive officers who did not elect to continue deferred distribution received all common shares for which distribution had been previously deferred (in respect of RSUs that had previously vested) on February 25, 2008. In the future, executive officers who did not elect to continue deferred distribution will receive immediately all common shares distributable upon vesting of unvested RSUs, beginning with the February 25, 2008 vesting date. The elimination of the defe rred distribution feature also resulted in the elimination of the ability to defer taxes for an additional four years.

All of the NEOs elected to continue deferred distribution of common shares upon vesting of RSUs granted under all of these programs except Mr. McHale, who elected to continue deferred distribution of common shares only for RSUs granted under the 2005 and 2006 programs. As a result, on February 25, 2008, NU distributed 1083 common shares to Mr. McHale and withheld 465 common shares to satisfy income tax withholding obligations in respect of previously vested RSUs granted under the 2004 long-term incentive program.

Share Ownership Guidelines

Effective in 2007, the Compensation Committee approved share ownership guidelines to emphasize the significance of increased share ownership by certain executive officers of NU and its subsidiaries. The Committee subsequently reviewed the guidelines for these executive officers and determined that they remain reasonable and require no modification. The guidelines call for Mr. Shivery, as Chief Executive Officer of NU, to own a minimum number of common shares valued at approximately six-times base salary, and the remaining executive officers to own a minimum number of NU common shares valued at approximately two to three-times base salary. The most prevalent share ownership level of Chief Executive Officers of utilities listed in our customized peer group was valued at approximately five-times base salary.

Executive Officer	Ownership Guidelines (Number of Shares)
CEO of NU	200,000
EVPs/SVPs of NU	45,000
Subsidiary presidents and key department heads	17,500

At the time the share ownership guidelines were implemented, the Committee required these executive officers to attain these ownership levels within five years. In 2007, the Committee amended the guidelines to require newly-hired executive officers to attain the ownership levels within seven years. All of our NEOs are currently at, or close to, these levels. Common shares, whether held of record, in street name, or in individual 401(k) accounts, and RSUs all satisfy the guidelines. Unexercised stock options do not count toward the ownership guidelines.

Performance Cash Program

General

The Performance Cash Program is a performance-based component of our long-term incentive program. Performance cash awards are equal to one-half of total individual long-term incentive awards at target. A new three-year program commences every year. Payment under a program depends on the extent to which NU achieves goals in the four metrics described below during each year of the program. The Compensation Committee determines the actual amounts payable, if any, only after the end of the final year in the respective program.

- Cumulative Adjusted Net Income, which is consolidated NU net income adjusted to exclude the effects of certain nonrecurring income and expense items or events (which we defined as ANI under the annual incentive program) over the three years in a program.
- Average adjusted ROE, which is the average of the annual ROE for NU for the three years in a program. The Committee adjusts average ROE on the same basis as cumulative adjusted net income.
- Average credit rating of NU, which is the time-weighted average daily credit rating by the rating agencies Standard & Poor's, Moody's, and Fitch. The metric is calculated by assigning numerical values to credit ratings (A or A2: 5; A- or A3: 4; BBB+ or Baa1: 3; BBB or Baa2: 2; and BBB- or Baa3: 1) so that a high numerical value represents a high credit rating. In addition to average credit rating objectives, the ratings by S&P and Moody's must remain above investment grade.
- Relative total NU shareholder return as compared to the return of the utility companies listed in the performance peer group identified for each Performance Cash Program.

The Committee weighs each of the four metrics equally, reflecting the Compensation Committee's belief that these areas are critical measurements of corporate success. The Committee measures NU's cumulative adjusted net income, average adjusted ROE, and average credit rating because these metrics are directly related to NU's multi-year business plan in effect at the beginning of the three-year program. The Committee also measures NU's relative total shareholder return to emphasize to the plan participants the importance of achieving total shareholder returns at or above the median return for companies listed in the program performance peer group. NU is required to achieve a minimum level of performance under each metric before any amount is payable with respect to that metric. If NU achieves the minimum level of performance, then the resulting payout will equal 50% of the target. If NU achieves the maximum level of performance, then the resulting payout will equal 150% of target. The Committee fixed the minimum opportunity at 50% of target and the maximum opportunity at 150% of target because the Committee believes this range is consistent with the ranges used by companies listed in the program performance peer group.

2005 – 2007 Performance Cash Program

The Compensation Committee approved NU's 2005 – 2007 Performance Cash Program in early 2005. Upon completion of NU's fiscal year ended 2007, the Committee determined that NU achieved goals under each of the four metrics during the three-year program and, accordingly, that awards under the program were payable at an overall level of 130% of target. The table set forth below describes the goals under the 2005 – 2007 program and our actual results during that period:

2005 – 2007 Program Goals

Goal	Minimum	Target	Maximum	Actual Result
NU Cumulative Adjusted Net Income ($ in millions)	$ 519.5	$ 611.2	$ 702.9	$ 693.8
Average Adjusted ROE	6.3%	7.4%	8.5%	8.7%
Average Credit Rating	1.4	2.0	2.8	1.7
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th	91st

(1) The performance peer group for the 2005 – 2007 program included NU and the following companies: Consolidated Edison, Inc., DTE Energy Company, Energy East Corporation, Great Plains Energy Incorporated, Integrys Energy Group, Inc., NiSource, Inc., NSTAR, Pepco Holdings, Inc., PPL Corporation, Wisconsin Energy Corporation and Xcel Energy Inc.

Based on NU financial performance during the three-year performance period of the 2005 – 2007 Performance Cash Program, the Committee approved the following payments: Mr. Shivery: $1,365,000; Mr. McHale: $268,190; Mr. Olivier: $325,000; Mr. Necci $138,190, Mr. Butler: $341,250, and Mrs. Grisé: $434,958. The payments were determined pursuant to formulas set forth in the 2005 – 2007 Performance Cash Program and were not subject to the discretion of the Compensation Committee.

2007 – 2009 Performance Cash Program

The Committee approved NU's 2007 – 2009 Performance Cash Program goals during early 2007. No amounts have been paid under this program, and the Committee will not determine whether any amounts are payable until the end of our 2009 fiscal year, which is the final year in the three-year program.

The 2007 – 2009 program also includes goals in four metrics: NU's cumulative adjusted net income, NU's average adjusted ROE, NU's average credit rating, and NU's relative total shareholder return. For the 2007 – 2009 program, cumulative adjusted net income and average adjusted ROE exclude the effects of the following nonrecurring income and expense items or events: accounting or tax law changes; unusual IRS or regulatory issues; unexpected costs related to nuclear decommissioning; unexpected costs related to environmental remediation of the HWP; divestiture or discontinuance of a segment or component of NU's business; mark-to-market impacts of agreements to which NU or any of its competitive subsidiaries are parties; unbudgeted charitable contributions; impairments on goodwill acquired before 2002 (more than five years prior to the beginning of this program cycle); and the impact of any settlement of, or final decision in, ong oing litigation with Con Edison.

The performance peer group for the 2007 – 2009 program includes NU and the following companies: Allegheny Energy, Inc., Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., Consolidated Edison, Inc., Energy East Corporation, NiSource, Inc., NSTAR, Pepco Holdings, Inc., Pinnacle West Capital Corporation, Puget Energy, Inc., SCANA Corporation, Sierra Pacific Resources, Wisconsin Energy Corporation and Xcel Energy Inc.

SUPPLEMENTAL BENEFITS

NU provides a variety of basic and supplemental benefits designed to assist it in attracting and retaining executive officers for NU System Companies critical to its success by reflecting competitive practices. The Compensation Committee endeavors to adhere to a high level of propriety in managing executive benefits and perquisites. We do not provide permanent lodging or personal entertainment for any executive officer or employee, and our executive officers are eligible to participate in substantially the same health care and benefit programs available to our employees.

RETIREMENT BENEFITS

NU provides retirement income benefits for employees of NU System Companies, including officers, who commenced employment before 2006 under the Northeast Utilities Service Company Retirement Plan (Retirement Plan) and, for officers, under the SERP for Officers of Northeast Utilities System Companies (Supplemental Plan). Each plan is a defined benefit pension plan, which determines retirement benefits based on years of service, age at retirement, and "plan compensation." Plan compensation for the Retirement Plan, which is a qualified plan under the Internal Revenue Code, includes primarily base pay and non-officer annual incentives up to the Internal Revenue Code limits for qualified plans. Beginning in 2006, newly-hired exempt employees, including executive officers, participate in an enhanced defined contribution retirement plan, called the K-Vantage benefit, instead of the Retirement Plan. Employees hired before 2006 continue to participate in the Retirement Plan, except for those who elected to participate in the K-Vantage benefit.

The Supplemental Plan adds to plan compensation: base pay over the Internal Revenue Code limits; deferred base salary; annual executive incentive program awards; and, for certain participants, long-term incentive program awards, as explained in the narrative accompanying the Pension Benefits Table.

The Supplemental Plan consists of two parts. The first part, called the make-whole benefit, reimburses participants for benefits lost due to Internal Revenue Code limitations on benefits provided under the Retirement Plan. The second part, called the target benefit, is available to all NEOs except Messrs. Olivier and Necci. The target benefit supplements the Retirement Plan and make-whole benefit under the Supplemental Plan so that, upon attaining at least 25 years of service, total retirement benefits from these plans will equal a target percentage of the final average compensation. To receive the target benefit, a participant must remain employed by NU or its subsidiaries at least until age 60, unless NU’s Board of Trustees establishes a lower age.

The value of the target benefit was reduced in 2005 to reflect changes in competitive practices, which indicated general reductions in the prevalence of defined benefit plans and the value of special retirement benefits to senior executives. Individuals who began serving as officers before February 2005 are eligible to receive a target benefit with the target percentage fixed at 60%. Individuals who began serving as officers from and after February 2005 are eligible to receive a target benefit with the target percentage fixed at 50%. As a result, Messrs. Shivery and Butler have target benefits at 60% while Mr. McHale has a target benefit at 50%.

Mr. Shivery’s employment agreement provides for a special total retirement benefit determined using the Supplemental Plan target benefit formula plus three additional years of company service. This benefit will be reduced by two percent per year for each year Mr. Shivery retires before age 65. Upon retirement, Mr. Shivery will be eligible to receive the cash value of retirement health benefits. See the Pension Benefits Table and the accompanying narrative for more details of these arrangements.

NU entered into an employment agreement with Mr. Olivier that includes retirement benefits similar to the benefits provided by his previous employer. Accordingly, Mr. Olivier is entitled to receive separate retirement benefits in lieu of the Supplemental Plan benefits described above. Pursuant to his agreement, Mr. Olivier will receive a targeted pension value if he meets certain eligibility requirements. See the Pension Benefits Table and the accompanying narrative for more details of this arrangement. As discussed under the caption entitled Mix of Compensation Elements above, Mr. Olivier’s long-term incentive plan targets and termination benefits are less than those provided to other similarly situated officers because of these separate retirement benefits.

401K PLAN

NU provides an opportunity for employees to save money for retirement on a tax-favored basis through the Northeast Utilities Service Company 401k Plan (401k Plan). The 401k Plan is a defined contribution plan under Section 401(k) of the Internal Revenue Code. Participants with at least six months of service receive employer matching contributions, not to exceed 3% of base compensation, one-third of which are in cash available for investment in various mutual fund alternatives and two-thirds of which are in the form of NU common shares (ESOP shares).

The K-Vantage benefit provides for employer contributions to the 401k Plan in amounts between 2.5% and 6.5% of plan compensation based on age and years of service. These contributions are in addition to employer matching contributions. Executive officers hired beginning in 2006 also participate in a companion nonqualified K-Vantage benefit that provides defined contribution benefits above Internal Revenue Code limits on qualified plans.

NONQUALIFIED DEFERRED COMPENSATION PLAN

Our executive officers participate in a Nonqualified Deferred Compensation Plan (Deferral Plan) to provide additional retirement benefits not available in the 401k Plan because of Internal Revenue Code limits on qualified plans. Under the Deferral Plan, executive officers are entitled to defer up to 100% of base salary and annual incentive awards. NU matches officer deferrals in an amount equal to 3% of the amount of base salary above Internal Revenue Code limits on qualified plans. The match is deemed to be invested in NU common shares and vests at the end of the third year after the calendar year in which the match was earned, or at retirement, whichever occurs first. Participants are entitled to select deemed investments for all deferred amounts from the same investments available in the 401k Plan. NU also credits the Deferral Plan in amounts equal to the K-Vantage benefit that would have been provided under the 401k Plan but for Internal R evenue Code limits on qualified plans. This nonqualified plan is unfunded. Please see the Nonqualified Deferred Compensation Table and the accompanying notes for additional plan details.

PERQUISITES

It is our philosophy and the philosophy of NU that perquisites should be provided to executive officers as needed for business reasons, and not simply in reaction to prevalent market practices.

With the exception of Mr. Necci, senior executive officers, including the other NEOs, are eligible to receive reimbursement for financial planning and tax preparation services. This benefit is intended to help ensure that executive officers seek competent tax advice, better prepare complex tax returns, and leverage the value of our compensation programs. Reimbursement is limited to $4,000 every two years for financial planning services and $1,500 per year for tax preparation services.

All executive officers receive a special annual physical examination benefit to help ensure serious health issues are detected early. The benefit is limited to the reimbursement of up to $500 for fees incurred beyond those covered by our medical plan.

When hiring a new executive officer, NU sometimes reimburses executive officers for certain temporary living and relocation expenses, or provides a lump sum payment in lieu of specific reimbursement. These expenses are grossed-up for income taxes attributable to such reimbursements.

When required for a valid business purpose, an executive officer may be accompanied by his or her spouse, in which case NU will reimburse the executive officer for all spousal travel expenses, including a gross-up for taxes.

Tax gross-ups are provided as described above only because of the direct corporate benefit to us when executive officers incur such expenses. The impact of the aggregate amount of the tax gross-ups is not material to us.

CONTRACTUAL AGREEMENTS

NU has entered into employment agreements with certain executive officers, including Messrs. Shivery, McHale, Olivier and Butler. The agreements specify compensation and benefits during the employment term and include benefits payable upon involuntary termination of employment and termination of employment following a change of control. We believe that these benefits are necessary to attract and retain competent and capable executive talent. We also believe that these benefits help to ensure our executive officers’ continued dedication and objectivity at a time when they might otherwise be concerned about their future employment.

In the event of a change of control, the agreements provide for enhanced cash severance benefits following termination of employment without "cause" (as defined in the employment agreement, generally involving a felony conviction; acts of fraud, embezzlement, or theft in the course of employment; intentional, wrongful damage to NU property; gross misconduct or gross negligence in the course of employment; or a material breach of obligations under the agreement) or upon termination of employment by the executive for "good reason" (as defined in the employment agreement, generally meaning an assignment to duties inconsistent with his position, a failure by the employer to satisfy material terms of the agreement or the transfer of the executive to an office location more than 50 miles from his or her principal place of business immediately prior to a change of control). The Compensation Committee believes that termination for good reason is conceptually th e same as termination "without cause" and, in the absence of this provision, potential acquirers would have an incentive to constructively terminate executives to avoid paying severance.

As defined in the employment agreements with Messrs. Shivery, McHale and Butler, a "change of control" means a change in ownership or control effected through (i) the acquisition of 20% or more of the combined voting power of NU common shares or other voting securities, (ii) a change in the majority of NU's Board of Trustees over a 24-month period, unless approved by a majority of the incumbent Trustees, (iii) certain reorganizations, mergers or consolidations where substantially all of the persons who were the beneficial owners of the outstanding NU common shares immediately prior to such business combination do not beneficially own more than 50% of the voting power of the resulting business entity, and (iv) complete liquidation or dissolution of NU, or a sale or disposition of all or substantially all of the assets of NU other than to an entity with respect to which following completion of the transaction more than 50% of common s hares or other voting securities is then owned by all or substantially all of the persons who were the beneficial owners of common shares and other voting securities immediately prior to such transaction.

Pursuant to the change of control provisions in the employment agreements, each NEO except for Messrs. Olivier and Necci will be reimbursed for the full amount of any excise taxes imposed on severance payments and any other payments under Section 4999 of the Internal Revenue Code. This "gross-up" is intended to preserve the aggregate amount of the severance payments by compensating the executive officers for any adverse tax consequences to which they may become subject under the Internal Revenue Code. The mechanics and impact of the termination arrangements in the employment agreements are described in more detail in the Potential Payments Upon Termination or Change of Control Tables, appearing further below. Severance payments to Messrs. Olivier and Necci may be reduced to avoid excise taxes.

To help protect us after the termination of an executive officer's employment, the employment agreements include non-competition and non-solicitation covenants pursuant to which the executive officers have agreed not to compete with NU or its subsidiaries, or solicit NU employees for a period of two years (one year for Messrs. Olivier and Necci) after termination of employment.

In the event of termination of employment without "cause" or upon termination of employment by an NEO for good reason, in each case following a change of control, the expiration date of all vested unexercised stock options held by our NEOs will be extended automatically for up to an additional 36 months, but not beyond the original expiration date, to provide these holders with an opportunity to benefit from increased shareholder value created by the change of control. Also, in the event of a change of control, the long-term incentive programs provide for the vesting, pro rata based on the number of days of employment during the performance period, and payment at target of performance cash, whether or not the executive's employment terminates, unless the Committee determines otherwise.

Finally, in the event of a change of control, the Nonqualified Deferred Compensation Plan provides for the immediate vesting of any employer matches, although these matches will be paid according to the schedule defined by the executive's original election.

As discussed under the caption entitled Supplemental Benefits above, our employment agreements with Messrs. Shivery and Olivier also include additional retirement benefits.

Mrs. Grisé resigned as chief executive officer of CL&P effective January 15, 2007 and retired from NU on July 1, 2007. At the time of her retirement, Mrs. Grisé affirmed the negative covenants under her employment agreement, including her agreement, for two years following her retirement, to refrain from engaging in activities on behalf of certain competitors, soliciting certain employees or interfering with NU's business relationships. In consideration of these covenants, NU agreed to provide Mrs. Grisé with a special retirement benefit which, when combined with her annual benefit under the Retirement Plan and the Supplemental Plan, and based on her annuity elections, will result in an annual payment of $618,681. On January 2, 2008, NU paid Mrs. Grisé a lump sum cash payment of $120,535 (i) as consideration for a standard general release of all claims against NU in connection with her employment, which she delivered to NU upon her retirement, and (ii) in lieu of a grant of RSUs and/or performance cash under the 2007-2009 Long-Term Incentive Program.

TAX AND ACCOUNTING CONSIDERATIONS

Tax Considerations. All executive compensation for 2007 was fully deductible by NU for federal income tax purposes, except for approximately $465,000 in RSU distributions to Mr. Shivery.

Section 162(m) of the Internal Revenue Code limits the tax deduction for compensation paid to a company's Chief Executive Officer and certain other executives. NU is entitled to deduct compensation payments above $1 million as compensation expense only to the extent that these payments are "performance based" in accordance with Section 162(m) of the Internal Revenue Code. NU's annual incentive program and performance cash program qualify as performance-based compensation under the Internal Revenue Code. As required by Section 162(m), the Compensation Committee reports to the Board of Trustees annually the extent to which various performance goals have been achieved. RSUs do not qualify as performance-based compensation.

Currently, Mr. Shivery is the only NEO to exceed the Section 162(m) limit. To preserve an employee compensation tax deduction for NU, Mr. Shivery agreed, for as long as it is beneficial to NU, to defer the distribution to him of

common shares in respect of all vested RSUs,

which will begin in the calendar year after he leaves NU, at which time Section 162(m) will no longer apply to him. The non-deductible RSU gains for Mr. Shivery in 2007 described above relate to RSU awards granted before Mr. Shivery was elected as NU's Chief Executive Officer.

Section 409A of the Internal Revenue Code provides that amounts deferred under nonqualified deferred compensation plans are includable in an employee's income when vested unless certain requirements are met. If these requirements are not met, employees are also subject to additional income tax and interest penalties. All of NU's supplemental retirement plans, severance arrangements, and other nonqualified deferred compensation plans currently meet, or will be amended to meet, these requirements. As a result, employees will be taxed when the deferred compensation is actually paid to them. NU will be entitled to a tax deduction at that time.

Section 280G of the Internal Revenue Code disallows a tax deduction for "excess parachute payments" in connection with the termination of employment related to a change of control (as defined in the Internal Revenue Code), and Section 4999 of the Internal Revenue Code imposes a 20% excise tax on any person who receives excess parachute payments. As discussed above, our NEOs are entitled to receive certain payments upon termination of their employment, including termination following a change of control. Under the terms of the agreements, all NEOs except Messrs. Olivier and Necci are entitled to receive tax gross-ups for any payments that constitute an excess parachute payment. Accordingly, NU's tax deduction would be disallowed under Section 280G for all excess parachute payments as well as tax gross-ups. Not all of the payments to which NEOs are entitled are excess parachute payments. The amounts of the payments that constitute excess parachute payment s are set forth in the tables found under the caption entitled Potential Payments at Termination or Change of Control, below.

In the event of a change of control in which NU is not the surviving entity, RSU awards granted to executive officers provide that the acquirer will assume or replace the awards, even if the executive remains employed after the change of control.

Accounting Considerations. RSUs disclosed in the Grants of Plan-Based Awards Table are accounted for based on their grant date fair value, as determined under Statement of Financial Accounting Standards (SFAS) No. 123(R), which is recognized over the service period, or the three-year vesting period applicable to the RSUs. Assumptions used in the calculation of this amount appear under the caption entitled Management's Discussion and Analysis and Results of Operations in our Annual Report to Shareholders, filed as an exhibit to our Annual Report on Form 10-K for the fiscal year ended December 31, 2007. Forfeitures are estimated, and the compensation cost of the awards will be reversed if the employee does not remain employed by NU throughout the three-year vesting period. Performance cash program payments are accounted for on a variable basis based on the most likely payment outcome.

COMPENSATION COMMITTEE REPORT

The Compensation Committee of the NU Board of Trustees (Compensation Committee) has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with CL&P management. Based on this review and discussion the Compensation Committee has recommended to the Board of Directors of CL&P that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

The Compensation Committee

E. Gail de Planque, Chair
Robert E. Patricelli, Vice Chair
Richard R. Booth
Cotton M. Cleveland
Sanford Cloud, Jr.
James F. Cordes
Elizabeth T. Kennan

Dated: February 12, 2008

SUMMARY COMPENSATION TABLE

The table below summarizes the total compensation paid or earned by our Chief Executive Officer, Mr. Olivier, our Senior Vice President and Chief Financial Officer, Mr. McHale, and the three other most highly compensated executive officers other than Mr. Olivier and Mr. McHale who were serving as executive officers at the end of 2007, including Mr. Shivery, the Chief Executive Officer of NU and our Chairman, and one former executive officer who would have been among the three other most highly compensated executive officers had she been serving as an executive officer at the end of 2007 (collectively, the Named Executive Officers or NEOs). As explained in the footnotes below, the amounts reflect the economic benefit to each Named Executive Officer of the compensation item paid or accrued on his or her behalf for the fiscal year ended December 31, 2007. The compensation shown for each executive officer was for all services in all capacities to NU and its subsidiaries. All salaries, annual incentive amounts and long-term incentive amounts paid to these executive officers were paid by Northeast Utilities Service Company, a service company subsidiary of NU.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Stock Awards ($) (3)	Option Awards ($) (4)	Non-Equity Incentive Plan Compensation ($) (5)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings ($) (6)	All Other Compensation ($) (7)	Total ($)
Charles W. Shivery	2007	987,308	--	1,779,313	--	3,048,360	1,326,931	49,026	7,190,938
Chairman	2006	918,846	--	1,061,205	--	1,698,395	1,274,011	40,691	4,993,148
David R. McHale	2007	434,135	--	296,891	--	755,810	614,481	7,603	2,108,920
Senior Vice President and Chief Financial Officer	2006	353,847	--	148,512	--	395,693	413,275	6,600	1,317,927
Leon J. Olivier	2007	462,096	--	306,115	--	777,226	251,556	15,042	1,812,035
Chief Executive Officer	2006	411,039	--	178,951	--	451,419	275,264	13,692	1,330,365
Raymond P. Necci	2007	295,846	--	129,195	--	346,850	1,460,754	9,299	2,241,944
President and Chief Operating Officer CL&P and Yankee Gas	2006	282,589	--	103,307	--	200,229	191,963	8,898	786,986
Gregory B. Butler	2007	382,244	--	319,716	--	731,950	195,321	12,941	1,642,172
Senior Vice President and General Counsel	2006	359,659	--	218,078	--	383,279	215,642	7,077	1,183,735
Cheryl W. Grisé	2007	354,671	--	200,900	--	622,604	2,059,805	8,994	3,246,974
Former Chief Executive Officer CL&P (8)	2006	532,295	--	494,672	--	530,613	479,176	16,396	2,053,152

(1) Includes amounts deferred by the Named Executive Officers under the Deferral Plan, as follows: Mr. Shivery: $29,619; Mr. Olivier: $124,766; Mr. Necci: $44,377; Mr. Butler: $3,822; and Mrs. Grisé: $5,774. For more information, see the Executive Contributions in the Last Fiscal Year column of the Non-Qualified Deferred Compensation Plans Table.

(2) No discretionary bonus awards were made to any of the Named Executive Officers in the fiscal year ended December 31, 2007.

(3) Reflects the dollar amounts recognized for financial statement reporting purposes for the fiscal year ended December 31, 2007, in accordance with the treatment of time-based RSU and restricted share grants under generally accepted accounting principles. The amounts reflect the accounting expense of shares granted in and prior to 2007. Assumptions used in the calculation of this amount appear under the caption entitled Management's Discussion and Analysis and Results of Operations in our annual report to shareholders for the fiscal year ended December 31, 2007.

In 2005, 2006 and 2007, the Named Executive Officers were granted RSUs that vest in equal annual installments over three years as long-term incentive compensation except for Mrs. Grisé, who was not granted RSUs in 2007. Pursuant to the long-term

incentive programs approved in 2007, subject to the officer's election in December 2007 to continue the automatic four-year deferral of one-half of RSUs that vest on a particular date, NU distributes common shares upon the vesting of RSUs, except with respect to RSUs granted to Mr. Shivery. NU defers the distribution of common shares upon vesting of RSUs granted to Mr. Shivery, which will begin in the calendar year after he leaves NU. RSU holders are eligible to receive dividend equivalents on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU common shares. Dividend equivalents are accounted for as additional common shares that accrue and are distributed simultaneously with the common shares issued upon vesting of the underlying RSUs.

In 2004, the Named Executive Officers were granted RSUs that vest in equal annual installments over four years as long-term incentive compensation. Pursuant to amendments to the long-term incentive programs approved in 2007, subject to the officer's election in December 2007 to continue the automatic four-year deferral of one-half of RSUs as they vest under the 2004 Program, NU distributes common shares with respect to RSUs upon vesting. Also in 2004, Mr. Shivery and Mrs. Grisé were granted RSUs that vest in equal annual installments over three years as partial payment of their awards under the 2003 Annual Incentive Program. In addition, upon his appointment as NU's Chairman, President and Chief Executive Officer in 2004, Mr. Shivery was granted 25,000 restricted shares that vest in equal annual installments over four years. NU pays dividends on these restricted shares during the vesting period to the same extent that divid ends are declared and paid on NU common shares.

In 2003, the Named Executive Officers were granted restricted shares that vest in equal annual installments over four years as long-term incentive compensation. NU pays dividends on these restricted shares during the vesting period to the same extent that dividends are declared and paid on NU common shares. In connection with her retirement on July 1, 2007, unvested RSUs held by Mrs. Grisé that would have vested on February 25, 2008, instead vested in proportion to the time she was employed with us after February 25, 2006. Additional information regarding Mrs. Grisé's retirement is available in the Post-Employment Compensation Table prepared for Mrs. Grisé.

(4) NU has not granted any stock options since 2002. Accordingly, NU did not grant stock options to any of the Named Executive Officers in 2007.

(5) Includes payments to the Named Executive Officers under the 2007 Annual Incentive Program (Mr. Shivery: $1,683,360; Mr. McHale: $487,620; Mr. Olivier: $452,226; Mr. Necci: $208,660; and Mr. Butler: $390,700). Also includes payments under the 2005 – 2007 Long-Term Incentive Program (Mr. Shivery: $1,365,000; Mr. McHale: $268,190; Mr. Olivier: $325,000; Mr. Necci: $138,190; Mr. Butler: $341,250; and Mrs. Grisé: $434,958). Performance goals under the 2007 Annual Incentive Program were communicated to each officer by Mr. Shivery or, in the case of Mr. Shivery, jointly by the Compensation Committee and Corporate Governance Committee, during the first 90 days of 2007. The Compensation Committee, acting jointly with the Corporate Governance Committee, determined the extent to which these goals were satisfied (based on input from Mr. Shivery, in the case of the other NEOs) in February 2008. Performance goals under the 2005 – 2007 Long-Ter m Incentive Program were communicated to each officer by Mr. Shivery or, in the case of Mr. Shivery, jointly by the Compensation Committee and Corporate Governance Committee, during the first 90 days of 2005. The Compensation Committee determined the extent to which the long-term goals were satisfied in February 2008.

(6) Includes the actuarial increase in the present value from December 31, 2006 to December 31, 2007 of the Named Executive Officer's accumulated benefits under all of NU's pension plans determined using interest rate and mortality rate assumptions consistent with those appearing under the caption entitled Management's Discussion and Analysis and Results of Operations in our annual report to shareholders for the fiscal year ended December 31, 2007. The Named Executive Officer may not be fully vested in such amounts. The change in pension value for Mr. Necci increased significantly in 2007, when his age made him eligible for early retirement under NU's pension plans. More information on this topic is set forth in the notes to the Pension Benefits table, appearing further below. There were no above-market earnings on deferrals in 2007.

Mrs. Grisé retired on July 1, 2007 and began receiving her qualified pension. See Post-Employment Compensation: Cheryl W. Grisé for a summary of payments to Mrs. Grisé.

(7) Includes matching contributions of $6,750 allocated by NU to the account of each of the Named Executive Officers under the 401k Plan and employer matching contributions under the Deferral Plan for the Named Executive Officers who deferred part of their salary in the fiscal year ended December 31, 2007 (Mr. Shivery: $22,869; Mr. Olivier: $7,113; Mr. Necci: $2,125; Mr. Butler: $4,717; and Mrs. Grisé: $1,911), plus tax gross-ups (Mr. Shivery: $7,455; Mr. Olivier: $1,155; Mr. Necci: $424; Mr. Butler: $1,474; and Mrs. Grisé: $333). Mr. McHale did not participate in the Deferred Compensation Plan. Also includes perquisites received by Mr. Shivery in the amount of $11,952 consisting of reimbursement of spousal travel expenses and a cell phone allowance.

(8) In connection with her retirement on July 1, 2007, on January 2, 2008, NU paid Mrs. Grisé a lump sum cash payment of $120,535 (i) as consideration for a standard general release of all claims against NU in connection with her employment, which she delivered to NU upon her retirement, and (ii) in lieu of a grant of RSUs and/or performance cash under the 2007-2009 long-term incentive program. This amount included interest accrued from July 1, 2007 through January 2, 2008. Additional information is set forth in the Post-Employment Compensation Table prepared for Mrs. Grisé.

GRANTS OF PLAN-BASED AWARDS DURING 2007

The Grants of Plan-Based Awards Table provides information on the range of potential payouts under all incentive plan awards during the fiscal year ended December 31, 2007. The table also discloses the underlying stock awards and the grant date for equity-based awards. NU has not granted any stock options since 2002. Accordingly, NU did not grant stock options to any of the Named Executive Officers in 2007.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Option Awards
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**(#) (3)**	**($) (4)**
Charles W. Shivery						
Annual Incentive (1)	2/13/2007	493,654	987,308	1,974,616	n/a	n/a
Long-Term Incentive (2)	2/13/2007	750,000	1,500,000	2,250,000	95,316	2,625,003
David R. McHale						
Annual Incentive (1)	2/13/2007	141,094	282,188	564,376	n/a	n/a
Long-Term Incentive (2)	2/13/2007	168,750	337,500	506,250	18,382	506,240
Leon J. Olivier						
Annual Incentive (1)	2/13/2007	150,181	300,362	600,724	n/a	n/a
Long-Term Incentive (2)	2/13/2007	148,450	296,900	445,350	16,170	445,322
Raymond P. Necci						
Annual Incentive (1)	2/13/2007	73,962	147,923	295,846	n/a	n/a
Long-Term Incentive (2)	2/13/2007	63,500	127,000	190,500	5,073	139,710
Gregory B. Butler						
Annual Incentive (1)	2/13/2007	124,229	248,458	496,916	n/a	n/a
Long-Term Incentive (2)	2/13/2007	145,350	290,700	436,050	13,723	377,931
Cheryl W. Grisé						
Annual Incentive (1)	2/13/2007	93,823	187,645	187,645	n/a	n/a
Long-Term Incentive (2)(5)	2/13/2007	--	--	--	--	--

(1) Amounts reflect the range of potential payouts, if any, under the 2007 Annual Incentive Program for each Named Executive Officer, as described in the Compensation Discussion and Analysis. The payment in 2008 for performance in 2007 is set forth in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table. The threshold payment under the Annual Incentive Program is 50% of target. However, based on Adjusted Net Income and individual performance, the actual payment under the Annual Incentive Program could be zero.

(2) Reflects the range of potential payouts, if any, pursuant to performance cash awards under the 2007 - 2009 Long-Term Incentive Program, as described in the Compensation Discussion and Analysis. Grants of three-year performance cash awards were made to officers during 2007 under the 2007 – 2009 Long-Term Incentive Program. Performance cash will be fully vested at the end of the performance period and paid in cash to the officer during the first fiscal quarter after the end of the performance period.

(3) Reflects the number of RSUs granted to each of the Named Executive Officers on February 13, 2007 under the 2007 – 2009 Long-Term Incentive Program. The RSUs will vest in equal installments on February 25, 2009, 2010 and 2011. Except for Mr. Shivery, NU will distribute NU common shares in respect of vested RSUs on a one-for-one basis immediately upon vesting

after reduction for applicable withholding taxes. For Mr. Shivery, NU will distribute common shares, after reduction for applicable withholding taxes, in respect of vested RSUs in three approximately equal annual installments beginning the later of (i) six months after he leaves NU and (ii) January of the calendar year following the year in which he leaves NU. RSU holders are eligible to receive dividend equivalents on outstanding RSUs held by them to the same extent that dividends are declared and paid on our common shares. Dividend equivalents are accounted for as additional common shares that accrue and are distributed simultaneously with the common shares issued upon vesting of the underlying RSUs. The Annual Incentive program does not have an equity component.

(4) Reflects the grant-date fair value of RSUs granted to the Named Executive Officers on February 13, 2007, under the 2007 – 2009 Long-Term Incentive Program determined pursuant to generally accepted accounting principles. The Annual Incentive program does not have an equity component.

(5) NU did not grant RSUs to Mrs. Grisé in 2007 because she had previously announced her intention to retire on July 1, 2007. Additional information is set forth in the Post-Employment Compensation Table prepared for Mrs. Grisé.

EQUITY GRANTS OUTSTANDING AT DECEMBER 31, 2007

The following table sets forth option, restricted share and RSU grants outstanding at the end of our fiscal year ended December 31, 2007 for each of the Named Executive Officers. All outstanding options were fully vested as of December 31, 2007.

	Option Awards (1)			Stock Awards	
Name	**Number of Securities Underlying Unexercised Options Exercisable (#)**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units that have not Vested (#)(2)**	**Market Value of Shares or Units of Stock that have not Vested ($)(3)**
Charles W. Shivery	29,024	18.90	06/11/2012	180,987	5,666,706
David R. McHale	--			31,621	990,058
Leon J. Olivier	--			30,768	963,359
Raymond P. Necci	--			12,121	379,502
Gregory B. Butler	--			30,368	950,833
Cheryl W. Grisé (4)	--			6,523	204,239

(1) NU has not granted stock options since 2002.

(2) An aggregate of 140,581 unvested RSUs vested on February 25, 2008 (Mr. Shivery: 87,901; Mr. McHale: 14,484; Mr. Olivier: 15,281; Mr. Necci: 6,581 and Mr. Butler: 16,334). An additional 94,444 unvested RSUs will vest on February 25, 2009 (Mr. Shivery: 60,489; Mr. McHale: 10,852; Mr. Olivier: 9,957; Mr. Necci: 3,805 and Mr. Butler: 9,341). An additional 50,842 unvested RSUs will vest on February 25, 2010 (Mr. Shivery: 32,597; Mr. McHale: 6,286; Mr. Olivier: 5,530; Mr. Necci: 1,735 and Mr. Butler: 4,693).

(3) The market value of RSUs is determined by multiplying the number of share units by $31.31, the closing price per share of NU common shares on December 31, 2007, the last trading day of the fiscal year.

(4) All of the unvested RSUs held by Mrs. Grisé vested on January 2, 2008. NU distributed common shares, net of taxes, to Mrs. Grisé in respect of these RSUs.

OPTIONS EXERCISED AND STOCK VESTED IN 2007

The following table reports amounts realized on equity compensation during the fiscal year ended December 31, 2007. In 2007, Messrs. McHale, Olivier and Necci, and Mrs. Grisé exercised options. The Stock Awards columns report the vesting of restricted share grants and RSU grants to the Named Executive Officers in February 2007.

	Option Awards		Stock Awards	
Name	**Number of Shares Acquired on Exercise (#)**	**Value Realized on Exercise ($) (1)**	**Number of Shares Acquired on Vesting (#) (2)**	**Value Realized on Vesting ($) (3)**
Charles W. Shivery	--	--	61,324	1,821,947
David R. McHale	7,500	59,841	9,119	270,922
Leon J. Olivier	19,900	261,120	10,892	323,610
Raymond P. Necci	23,500	247,363	5,909	175,552
Gregory B. Butler	--	--	13,292	394,905
Cheryl W. Grisé	171,228	2,321,646	29,882	887,784

(1) Represents the amounts realized upon option exercises, which is the difference between the option exercise price and the market price on the date of exercise.

(2) Includes common shares distributed in respect of special grants of RSUs to Mr. Shivery (3,371 shares) and Mrs. Grisé (5,570 shares) during 2004 in connection with awards under the 2003 Annual Incentive Program. Also includes 6,250 restricted shares granted to Mr. Shivery upon his appointment as NU's Chairman, President and Chief Executive Officer in 2004, for which restrictions lapsed during 2007.

Also includes awards granted to our Named Executive Officers under our long-term incentive programs, as follows:

Name	2003 Program	2004 Program	2005 Program	2006 Program
Charles W. Shivery	10,140	5,748	14,879	27,186
David R. McHale	1,130	1,006	2,533	4,450
Leon J. Olivier	1,388	1,174	4,015	4,315
Raymond P. Necci	1,185	1,000	1,706	2,018
Gregory B. Butler	1,945	3,592	3,224	4,529
Cheryl W. Grisé	5,746	5,568	6,068	6,930

In all cases, NU reduces the distribution of common shares by that number of shares valued in an amount sufficient to satisfy tax withholding obligations, which amount NU distributes in cash. Included in the value realized are values associated with deferred RSUs, which are also reported in the Registrant Contributions in Last Fiscal Year column of the Non-Qualified Deferred Compensation Table.

(3) Value realized is based on $29.71 per share, the closing price of common shares on February 23, 2007. This value includes the value of vested RSUs for which the distribution of common shares is currently deferred.

PENSION BENEFITS IN 2007

The Pension Benefits Table sets forth the estimated present value of accumulated retirement benefits that would be payable to each Named Executive Officer, except for Mrs. Grisé, upon his retirement as of the first date upon which he is eligible to receive an unreduced pension benefit (see below). The table distinguishes the benefits among those available through the Retirement Plan, the Supplemental Plan and any additional benefits available under the respective officer's employment agreement. The Supplemental Plan provides a make whole benefit that is based in part on compensation that is not permitted to be recognized under a tax-qualified plan and provides a target benefit if the eligible officer continues his employment until age 60. Benefits under the Supplemental Plan are also based on elements of compensation that are not included under the Retirement Plan. This includes compensation equal to: (i) deferred compensation; (ii) the value of awards under the Annual Incentive Program for officers; and (iii) long-term incentive awards only for Messrs. McHale and Butler (as to each of their respective make whole benefits) and Mrs. Grisé (as to her target benefit), the values of which are frozen at the 2001 target levels.

The present value of accumulated benefits shown in the Pension Benefits Table was calculated as of December 31, 2007 assuming benefits would be paid in the form of a 50% contingent annuitant option (the typical form of payment for the target benefit), except for Mrs. Grisé, who chose the 75% contingent annuitant option upon her retirement. For Mr. Olivier, who has a special retirement arrangement, we assumed that his special retirement benefit would be paid as a lump sum, and his Retirement Plan benefit would be paid in the form of a 33.33% contingent annuitant option (the typical form of payment under the Retirement Plan). For Mr. Necci, we assumed all benefits would be paid in the form of a 33.33% contingent annuitant option (the typical form of payment under the Retirement Plan). For this table, we assumed that none of Mr. Olivier's benefits are provided under the Supplemental Plan. In addition, the present value of accrued benefits for an y Named Executive Officer assumes that benefits commence at the earliest age at which the participant would be eligible to retire and receive unreduced benefits. Named Executive Officers are eligible to receive unreduced benefits upon the earlier of (a) attainment of age 65 or (b) attainment of at least age 55 when age plus service equals 85 or more years, except for Mr. Olivier. Mr. Olivier's unreduced benefit is available at age 60 pursuant to his employment agreement. The target benefit is available for Messrs. Butler and McHale only after age 60. Accordingly, Mr. Shivery is eligible to receive unreduced benefits at age 65, Messrs. McHale and Olivier are eligible to receive unreduced benefits at age 60 and Mr. Butler is eligible to receive unreduced benefits at age 62. Mr. Necci became eligible to receive unreduced benefits at age 55 and is currently eligible to retire.

The limitations applicable to the Retirement Plan under the Internal Revenue Code as of December 31, 2007 were used to determine the benefits under each plan. The accrued benefits reflect actual compensation (both salary and incentives) earned during 2007. Under the terms of the Supplemental Plan, annual incentives earned for services provided in a plan year are deemed to have been paid rateably over that plan year. For example, the March 2008 payment pursuant to the 2007 annual incentive program was reflected in the 2007 plan compensation. We determined the present value of the benefit at retirement age by using the discount rate of 6.60% under SFAS No. 87 for the 2007 fiscal year end measurement (as of December 31, 2007). This present value assumes no pre-retirement mortality, turnover or disability. However, for the postretirement period beginning at the retirement age, we used the RP2000 Combined Healthy mortality table as published by the Society of Actuarie s (same table used for financial reporting under FAS 87). Additional assumptions appear under the caption entitled Management's Discussion and Analysis and Results of Operations in our annual report to shareholders for the fiscal year ended December 31, 2007.

Pension Benefits

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
Charles W. Shivery (1)	Qualified Plan	5.6	144,671	--
	Supplemental Plan	5.6	2,595,104	--
	Other Special Benefit	8.6	1,472,337	--
David R. McHale	Qualified Plan	26.3	399,757	--
	Supplemental Plan	26.3	1,386,262	--
Leon J. Olivier (2)	Qualified Plan	8.8	260,225	--
	Supplemental Plan	6.3	--	--
	Other Special Benefit	6.3	1,428,663	--
	Other Special Benefit	32.3	1,241,765	105,966
Raymond P. Necci	Qualified Plan	31.3	1,150,052	--
	Supplemental Plan	31.3	1,354,069	--
Gregory B. Butler	Qualified Plan	11.0	171,856	--
	Supplemental Plan	11.0	821,985	--
Cheryl W. Grisé (3)	Qualified Plan	26.9	747,040	28,525
	Supplemental Plan	26.9	7,635,240	--

(1) Mr. Shivery's actual service with NU totaled 5.6 years at December 31, 2007. However, Mr. Shivery's employment agreement provides for a special retirement benefit consisting of an amount equal to the difference between: (i) the equivalent of fully-vested benefits under the Retirement Plan and the Supplemental Plan calculated by adding three years to his actual service and using an early retirement commencement reduction factor of two percent per year for each year Mr. Shivery's age upon retirement is under age 65, if that factor yields a more favorable result to Mr. Shivery than the factors then in use under the Retirement Plan, and (ii) benefits otherwise payable from the Retirement Plan and the Supplemental Plan. The value of the additional three years of service on December 31, 2007 was approximately $1,472,337.

(2) Mr. Olivier was employed with Northeast Nuclear Energy Company (NNECO), one of our affiliates, from October of 1998 through March of 2001. In connection with this employment, he received a special retirement benefit that provided credit for service with NNECO when calculating the value of his defined benefit pension, offset by the pension benefit provided by NNECO. The benefit, which commenced upon Mr. Olivier's 55th birthday, provides an annuity of $105,966 per year in a form that provides no contingent annuitant benefit. The present value of future payments under this benefit was calculated using the actuarial assumptions currently used by the Retirement Plan. Mr. Olivier was rehired by NU in September 2001. Mr. Olivier's current employment agreement provides for certain supplemental pension benefits in lieu of benefits under the Supplemental Plan if certain eligibility requirements are met, in order to provide a benefit s imilar to that provided by NNECO. Under this arrangement, if Mr. Olivier remains continuously employed by NU until September 10, 2011 (or terminates his employment earlier with NU's consent), he will be eligible to receive a special benefit, subject to reduction for termination prior to age 65, consisting of three percent of final average compensation for each of his first 15 years of service since September 10, 2001, plus one percent of final average compensation for each of the second 15 years of service. Alternatively, if Mr. Olivier voluntarily terminates his employment with NU after his 60th birthday, or NU terminates his employment earlier for any reason other than "cause" (as defined in his employment agreement, generally meaning willful and continued failure to perform his duties after written notice, a violation of NU's Standards of Business Conduct or conviction of a felony) he is eligible to receive upon retirement a lump sum payment of $2,050,000 in lieu of benefits under the Supplemental Plan and the benefit described in the preceding sentence. These supplemental pension benefits will be offset by the value of any benefits he receives from the Retirement Plan. If the conditions described above are not met, then Mr. Olivier would be eligible for the make whole benefit under the Supplemental Plan. Amounts reported in the table assume the termination of his employment at age 60 and payment of the lump sum benefit of $2,050,000, offset by Retirement Plan benefits.

(3) Mrs. Grisé retired from NU effective July 1, 2007 with a vested benefit of $4,754 per month in the Retirement Plan.

NONQUALIFIED DEFERRED COMPENSATION IN 2007

Name	Executive Contributions in Last FY ($)(1)	Registrant Contributions in Last FY ($)(2)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($)(3)
Charles W. Shivery	29,619	1,358,004	74,652	--	2,376,430
David R. McHale	--	118,675	4,903	--	201,311
Leon J. Olivier	124,766	148,298	91,760	--	1,196,301
Raymond P. Necci	44,377	72,297	8,513	--	247,489
Gregory B. Butler	3,822	173,276	9,666	--	366,170
Cheryl W. Grisé	5,774	277,699	34,025	--	878,573

(1) Reflects base salary deferrals by the Named Executive Officers under the Deferral Plan for 2007. Named Executive Officers who participate in the Deferral Plan are provided with a variety of investment opportunities, which the individual can modify and reallocate at any time. Fund gains and losses are updated daily by our recordkeeper, Fidelity Investments. Contributions by the Named Executive Officer are vested at all times; however, the employer matching contribution vests after three years and will be forfeited if the executive's employment terminates, other than for retirement, prior to vesting.

(2) Includes employer matching contributions made to the Deferral Plan as of December 31, 2007 and posted on January 31, 2008, as reported in the All Other Compensation column of the Summary Compensation Table (Mr. Shivery: $22,869; Mr. Olivier: $7,113; Mr. Necci: $2,125, Mr. Butler: $4,717; and Mrs. Grisé: $1,911). The employer matching contribution is deemed to be invested in common shares but is paid in cash at the time of distribution. All other amounts relate to the value of common shares, the distribution of which was automatically deferred upon vesting of underlying RSUs pursuant to the terms of the respective Long-Term Incentive Programs, calculated using the closing price of the common shares on either the vesting date (February 25, 2007) or the last trading day prior to the vesting date if the vesting date falls on a weekend or holiday. For more information, see the footnotes to the Options Exerc ised and Stock Vested Table.

(3) Includes the total market value of Deferral Plan balances at December 31, 2007 plus the value of vested RSUs for which the distribution of common shares is currently deferred, based on $31.31 per share, the closing price of our common shares on December 31, 2007.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE OF CONTROL

In the event of a change of control, Messrs. Shivery, McHale, Olivier and Butler are each entitled to receive compensation and benefits following termination of employment without "cause" or upon termination of employment by the executive for "good reason." The Compensation Committee believes that termination for "good reason" is conceptually the same as termination "without cause" and, in the absence of this provision, potential acquirers would have an incentive to constructively terminate executives to avoid paying severance. Termination for "cause" generally means due to a felony conviction; acts of fraud, embezzlement, or theft in the course of employment; intentional, wrongful damage to company property; gross misconduct or gross negligence in the course of employment; or a material breach of obligations under the agreement. Termination for "good reason" generally is deemed to occur following an assignment to duties inconsistent with his position, a failure by the employer to satisfy material terms of the agreement, or the transfer of the executive to an office location more than 50 miles from his or her principal place of business immediately prior to a change of control.

Generally, a "change of control" means a change in ownership or control effected through (i) the acquisition of 20% or more of the combined voting power of common shares or other voting securities of NU, (ii) a change in the majority of the Board of Trustees of NU over a 24-month period, unless approved by a majority of the incumbent Trustees, (iii) certain reorganizations, mergers or consolidations where substantially all of the persons who were the beneficial owners of the outstanding NU common shares immediately prior to such business combination do not beneficially own more than 50% of the voting power of the resulting business entity, and (iv) complete liquidation or dissolution of NU, or a sale or disposition of all or substantially all of the assets of NU other than to an entity with respect to which following completion of the transaction more than 50% (75% for Messrs. Olivier and Necci) of common shares or other voting securities is then owned by all or substantially all of the persons who were the beneficial owners of common shares and other voting securities immediately prior to such transaction.

The discussion and tables below reflect the amount of compensation that would be payable to each of the Named Executive Officers, except for Mrs. Grisé, in the event of: (i) termination of employment for cause; (ii) voluntary termination; (iii) involuntary not-for-cause termination (or voluntary termination for good reason); (iv) termination in the event of disability; (v) death; and (vi) termination following a change of control. The amounts shown assume that each termination was effective as of December 31, 2007, the last business day of the fiscal year as required under SEC reporting requirements.

Payments Upon Termination

Regardless of the manner in which the employment of a Named Executive Officer terminates, he is entitled to receive certain amounts earned during his term of employment. Such amounts include:

- Vested restricted shares and RSUs;
- Amounts contributed under the Deferral Plan;
- Vested matching contributions under the Deferral Plan;
- Pay for unused vacation; and
- Amounts accrued and vested through the Retirement Plan, the 401k Plan and the Supplemental Plan.

I. Post-Employment Compensation: Termination for Cause

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Necci ($)	Butler ($)
Incentive Programs (1)					
Annual Incentives	--	--	--	--	--
Performance Cash	--	--	--	--	--
Restricted Stock and RSUs	2,106,185	201,311	254,850	134,178	349,458
Pension and Deferred Compensation					
Qualified Retirement Plan (2)	155,498	262,348	189,224	1,150,052	133,144
Supplemental Plan Payments (2)	--	--	--	--	--
Special Retirement Benefit (2)	--	--	--	--	--
Deferral Plan (3)	175,727	--	917,443	111,026	11,296
Other Benefits					
Health and Welfare Cash Value	--	--	--	--	--
Perquisites	--	--	--	--	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement	--	--	--	--	--
Separation Payment for Liquidated Damages	--	--	--	--	--
Total	**$2,437,410**	**$463,659**	**$1,361,517**	**$1,395,256**	**$493,898**

(1) The assumed termination date for purposes of this table is December 31, 2007. Only those RSUs that were previously vested but for which common shares were not distributed would be payable upon termination of employment for cause.

(2) Only vested benefits under the Retirement Plan would be available to Named Executive Officers in the event of termination of employment for cause. With the exception of Mr. Shivery and Mr. Necci, all of our Named Executive Officers are vested and eligible to receive a reduced benefit beginning at age 55 under the Retirement Plan. Mr. Necci became eligible to receive an unreduced benefit beginning at age 55. With the exception of Mr. Necci, none of the other Named Executive Officers has satisfied the minimum requirements for the make-whole benefit.

(3) The amounts in this row represent vested balances in the Deferral Plan at December 31, 2007, which would be payable in accordance with previous distribution elections following termination of employment for any reason.

II. Post-Employment Compensation: Voluntary Termination

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Necci ($)	Butler ($)
Incentive Programs (1)					
Annual Incentives	1,683,360	487,620	452,226	208,660	390,700
Performance Cash	2,706,420	268,190	590,915	258,580	341,250
Restricted Stock and RSUs	4,270,458	201,311	659,895	308,627	349,458
Pension and Deferred Compensation					
Qualified Retirement Plan (2)	181,315	262,348	189,224	1,150,052	133,144
Supplemental Plan Payments (2)	3,252,426	--	--	1,354,069	--
Special Retirement Benefit (2)	1,845,270	--	1,241,765	--	--
Deferral Plan (3)	270,245	--	941,451	113,311	11,296
Other Benefits					
Health and Welfare Cash Value (4)	99,704	--	--	--	--
Perquisites	--	--	--	--	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement	--	--	--	--	--
Separation Payment for Liquidated Damages	--	--	--	--	--
Total	**$14,309,198**	**$1,219,469**	**$4,075,476**	**$3,393,299**	**$1,225,848**

(1) All Named Executive Officers would receive a payout under the 2007 Annual Incentive Program and the 2005-2007 Performance Cash Program based on actual results. All current Performance Cash Programs provide for pro-rated payout in the event that a participant's employment terminates for retirement, death, or disability prior to the end of the performance period. "Retirement" is defined as eligibility to immediately commence a post-employment benefit under the Retirement Plan, Supplemental Plan or other employment agreement with NU or one of its subsidiaries. Messrs. Shivery, Olivier and Necci satisfy this definition and would, therefore, be entitled to receive prorated payouts under the 2006 – 2008 and 2007 – 2009 Performance Cash Programs, which payments would be based on year-end results and paid in the first quarters of 2008 and 2009, respectively. The amounts reflected in the table are projections assuming target perfor mance under the Performance Cash Programs. For RSUs granted under the Long-Term Incentive Programs that commenced in 2004, 2005, 2006 and 2007, Messrs. Shivery, Olivier and Necci would be entitled to receive a prorated payout of unvested RSUs for time worked in the vesting period that would otherwise be completed on February 25, 2008. All Named Executive Officers would receive full payment for all previously vested RSUs for which common shares had not yet been distributed.

(2) Pension amounts are present values at the end of 2007 of life annuities payable to each Named Executive Officer at age 65 (age 60 for Mr. Olivier, and age 55 for Mr. Necci). All assumptions used to calculate these pension values are the same as those described in the notes attached to the Pension Benefits Table.

(3) The deferred compensation values are vested balances for all Named Executive Officers. Messrs. Shivery, Olivier, and Necci are eligible for accelerated vesting of employer matches for 2004 through 2006 because of their retirement eligibility. Mr. Butler would forfeit these unvested matches upon voluntary termination of employment. Mr. McHale does not participate in the Deferral Plan.

(4) Mr. Shivery's employment agreement provides for immediate eligibility to receive retiree health benefits upon retirement which would be provided in cash in lieu of such benefits.

III. Post-Employment Compensation: Involuntary Termination, Not for Cause

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Necci ($)	Butler ($)
Incentive Programs (1)					
Annual Incentives	1,683,360	487,620	452,226	208,660	390,700
Performance Cash	2,706,420	268,190	590,915	258,580	341,250
Restricted Stock and RSUs	7,772,891	201,311	659,895	308,627	349,458
Pension and Deferred Compensation					
Qualified Retirement Plan (2)	176,678	299,813	271,922	1,150,052	151,451
Supplemental Plan Payments (2)	3,141,932	--	--	1,354,069	--
Special Retirement Benefit (2)	2,972,333	1,100,305	1,778,078	--	930,265
Deferral Plan (3)	270,245	--	941,451	113,311	11,296
Other Benefits					
Health and Welfare Cash Value (4)	81,248	10,044	72,175	1,611	93,649
Perquisites	7,000	7,000	7,000	--	7,000
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement (5)	1,974,616	716,323	--	--	630,703
Separation Payment for Liquidated Damages (5)	1,974,616	716,323	--	--	630,703
Total	**$22,761,339**	**$3,806,929**	**$4,773,662**	**$3,394,910**	**$3,536,475**

(1) Messrs. Shivery, Olivier and Necci would satisfy the criteria for retirement treatment under the Long-Term Incentive Program as described in the Voluntary Termination Table. Mr. Shivery's employment agreement provides for full vesting and distribution of all restricted shares and common shares in respect of RSUs upon involuntary termination of employment without cause. NU would distribute to all Named Executive Officers common shares in respect of all previously vested RSUs for which common shares had not been distributed.

(2) Employment agreements with Messrs. Shivery, McHale and Butler provide for the addition of two years of age and service in the calculation of pension benefits available upon an involuntary termination without cause. For Mr. Shivery, the two additional years of age and service is in addition to the three additional years of service to which he is entitled upon voluntary termination of employment. Pension amounts reflected above are the present values at the end of 2007 of benefits payable to each Named Executive Officer at the earliest unreduced benefit age (Mr. Shivery: age 63; Mr. McHale: age 63; Mr. Olivier: age 58; Mr. Necci: age 55 and Mr. Butler: age 62). Except for the benefit payable to Mr. Olivier, these benefits are annuities calculated using the same assumptions described in the notes to the Pension Benefits Table. Under the terms of his employment agreement, if Mr. Olivier’s employment is terminated for a ny reason other than for "cause" (as defined in his employment agreement, generally meaning willful and continued failure to perform his duties after written notice, a violation of NU’s Standards of Business Conduct or conviction of a felony), he will be immediately eligible to receive a special retirement benefit of $2,050,000 paid as a lump sum, offset by benefits from the Retirement Plan.

(3) The deferred compensation values are vested balances for all Named Executive Officers. Messrs. Shivery, Olivier, Necci and Butler are eligible for accelerated vesting of the employer matches for 2004 through 2006 because of their retirement eligibility.

(4) Employment agreements with Messrs. Shivery, McHale and Butler provide for the payment of two years of active benefits value and retirement benefits if adding the "two additional years" of age and service would have made the officer eligible under the retiree health plan. Mr. Shivery’s employment agreement provides for automatic eligibility for retiree health benefits, and Mr. Olivier’s employment agreement provides for retiree health benefits if his employment terminates involuntarily without cause. Six months of employer-paid COBRA benefits are generally made available to all employees whose employment terminates involuntarily without cause. Thus, the amounts reported in the table are the cash value of 18 months of employer contributions toward active employee benefits for all Named Executive Officers, plus retiree benefits for Messrs. Shivery, Olivier and Butler after 24 months, each of whom would not otherwise be eligible for retiree health benefits except as provided under their employment agreements. These amounts would be paid as a lump sum and grossed up for applicable withholding taxes. With the exception of Mr. Necci, all of the NEOs are also eligible to receive reimbursement for two years of financial planning and tax preparation services.

(5) Employment agreements with Messrs. Shivery, McHale and Butler provide for a severance payment equal to two times the base salary plus annual incentives at target, one multiple of which is conditioned upon the execution of a non-competition agreement.

IV. Post-Employment Compensation: Termination Upon Disability

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Necci ($)	Butler ($)
Incentive Programs (1)					
Annual Incentives	1,683,360	487,620	452,226	208,660	390,700
Performance Cash	2,706,420	518,517	590,915	258,580	613,498
Restricted Stock and RSUs	4,270,458	201,311	659,895	308,627	349,458
Pension and Deferred Compensation					
Qualified Retirement Plan (2)	181,315	592,797	260,225	1,150,052	171,486
Supplemental Plan Payments (2)	3,252,426	2,041,949	--	1,354,069	822,353
Special Retirement Benefit (2)	1,845,270	--	1,428,663	--	--
Deferral Plan (3)	270,245	--	941,451	113,311	11,296
Other Benefits					
Health and Welfare Cash Value (4)	92,899	--	82,961	--	--
Perquisites	--	--	--	--	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement	--	--	--	--	--
Separation Payment for Liquidated Damages	--	--	--	--	--
Total	**$14,302,393**	**$3,842,194**	**$4,416,336**	**$3,393,299**	**$2,358,791**

(1) All current long-term Performance Cash Programs provide for a prorated payout in the event that a participant's employment terminates prior to the end of the performance period for reason of disability. While actual values are reported for the 2007 Annual Incentive Program and the 2005 – 2007 Performance Cash Program amounts, amounts shown for the Performance Cash Program for 2006 – 2008, and 2007 – 2009 are based on target performance in accordance with program rules and prorated for time worked in the performance period. For RSUs, a disabled participant would receive payout of unvested RSUs prorated for time worked in the vesting period that would otherwise be completed on February 25, 2008 plus payment for all previously vested but not yet paid RSUs.

(2) Under our Long-Term Disability (LTD) program, disabled participants in the Retirement Plan are allowed to continue to accrue service in the Retirement Plan during the period when they are receiving disability payments. Disability payments stop when the LTD participant elects to commence pension payments, but not later than age 65. We have assumed similar treatment in the development of the pension amounts reported in this table. For purposes of valuing the pension benefits, we have assumed that each Named Executive Officer would remain on LTD until his first unreduced make whole or target pension benefit age (Mr. Shivery, age 65; Mr. McHale, age 55; Mr. Olivier, age 60; Mr. Necci, age 55; and Mr. Butler, age 62). Except for the benefit payable to Mr. Olivier, all payments would consist of life annuities calculated using the same assumptions detailed in the notes to the Pension Benefits Table. Mr. Olivier's benefit would be paid as a lump sum of $2,050,000, offset by benefits from the Retirement Plan.

(3) The deferred compensation values are vested balances for all Named Executive Officers because all unvested employer matching contributions would become vested upon disability.

(4) Mr. Olivier’s employment agreement provides for retiree health benefits if his employment terminates involuntarily without cause, even if he would not otherwise qualify for such benefits. The amount reported is the value of our contributions for these benefits paid as a lump sum grossed up for applicable withholding taxes. Mr. Shivery’s employment agreement provides for immediate eligibility to receive retiree health benefits upon retirement, which would be provided as cash in lieu of such benefits.

V. Post-Employment Compensation: Death

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Necci ($)	Butler ($)
Incentive Programs (1)					
Annual Incentives	987,308	282,188	300,362	147,923	248,459
Performance Cash	2,706,420	518,517	590,915	258,580	613,498
Restricted Stock and RSUs	4,270,458	201,311	659,895	308,627	349,458
Pension and Deferred Compensation					
Qualified Retirement Plan (2)	169,809	1,031,233	271,922	1,082,912	120,786
Supplemental Plan Payments (2)	3,045,348	3,523,147	--	1,275,018	263,443
Special Retirement Benefit (2)	1,727,805	--	1,778,078	--	--
Deferral Plan (3)	270,245	--	941,451	113,311	11,296
Other Benefits					
Health and Welfare Cash Value (4)	55,599	--	38,443	--	--
Perquisites	--	--	--	--	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement	--	--	--	--	--
Separation Payment for Liquidated Damages	--	--	--	--	--
Total	**$13,232,992**	**$5,556,396**	**$4,581,066**	**$3,186,371**	**$1,606,940**

(1) The 2006-2008 and 2007-2009 Performance Cash Programs provide for a prorated payout in the event that a participant's employment terminates prior to the end of the performance period for reason of death. All such payments would be prorated for time worked in each performance period and paid at target. For RSUs, a deceased participant's beneficiary would receive a prorated payout of unvested RSUs for time worked in the vesting period that would otherwise be completed on February 25, 2008 plus payment for all previously vested but not yet paid RSUs.

(2) Represents the lump sum present value of pension payments to the surviving beneficiary of each Named Executive Officer.

(3) The deferred compensation values are vested balances for all Named Executive Officers since all unvested employer matching contributions would become vested on account of death.

(4) Upon his death, Mr. Olivier’s employment agreement provides for retiree health benefits for his spouse if she would not otherwise qualify for such benefits. The amount reported is the value of our contributions for these benefits paid as a lump sum grossed up for applicable withholding taxes.

Payments Made Upon a Change of Control:

The employment agreements with Messrs. Shivery, McHale, Olivier and Butler include change of control benefits. NU has not entered into an employment agreement with Mr. Necci. Messrs. Olivier and Necci participate in the Special Severance Program for Officers of Northeast Utilities System Companies (SSP) which provides benefits upon termination of employment in connection with a change of control. The employment agreements and the SSP are binding on NU and, except for Mr. Shivery’s agreement, on certain of NU’s majority-owned subsidiaries, including us. The terms of the various employment agreements are substantially similar, except for the agreement with Mr. Olivier, which refers instead to the change of control provisions of the SSP.

Pursuant to the employment agreements and under the terms of the SSP, if an executive officer’s employment terminates following a change of control, other than termination of employment for "cause" (as defined in the employment agreements, generally meaning wilful and continued failure to perform his duties after written notice, a violation of NU’s Standards of Business Conduct or conviction of a felony), or by reason of death or disability), or if the executive officer terminates his employment for "good reason" (as defined in the employment agreements, generally meaning an assignment to duties inconsistent with his position, a failure by the employer to satisfy material terms of the agreement or the transfer of the executive to an office location more than 50 miles from his or her principal place of business immediately prior to a change of control), then the executive officer will receive the benefits listed below, which receipt is co nditioned upon delivery of a binding release of all legal claims against NU and its subsidiaries:

- A lump sum severance payment (except for Messrs. Olivier and Necci) of two-times the sum of the executive’s base salary plus all annual awards that would be payable for the relevant year determined at target (Base Compensation);

- As consideration for a non-competition and non-solicitation covenant, a lump sum payment in an amount equal to the Base Compensation (equal to two-times Base Compensation for Messrs. Olivier and Necci under the terms of the SSP);

- Health continuation coverage, or the cash equivalent, paid by us for three years (two years for Mr. Olivier). Mr. Necci is eligible to retire and would therefore be eligible for retiree benefits;

- Benefits as if provided under the Supplemental Plan, notwithstanding eligibility requirements for the Target Benefit, including favorable actuarial reductions and the addition of three years to the executive's age and years of service as compared to benefits available upon voluntary termination of employment (except for Mr. Olivier, whose benefits are described below, and Mr. Necci);

- Automatic vesting and distribution of common shares in respect of all unvested RSUs; and

- A lump sum payment in an amount equal to the excise tax charged to the executive under the Internal Revenue Code as a result of the receipt of any change of control payments, plus tax gross-up (except for Messrs. Olivier and Necci).

The summaries of the employment agreements above do not purport to be complete and are qualified in their entirety by the actual terms and provisions of the employment agreements, copies of which have been filed as exhibits to our Annual Report on Form 10-K for the year ended December 31, 2007.

VI. Post-Employment Compensation: Termination Following a Change of Control

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Necci ($)	Butler ($)
Incentive Programs (1)					
Annual Incentives	1,683,360	487,620	452,226	208,660	390,700
Performance Cash	4,125,000	811,990	871,900	382,090	894,550
Restricted Stock and RSUs	7,772,891	1,191,369	1,218,209	513,682	1,300,291
Pension and Deferred Compensation					
Qualified Retirement Plan (2)	181,315	319,037	271,922	1,150,052	161,197
Supplemental Plan Payments (2)	3,252,426	--	--	1,354,069	--
Special Retirement Benefit (2)	3,690,540	1,200,788	1,778,078	--	1,103,689
Deferral Plan (3)	270,245	--	941,451	113,311	11,296
Other Benefits					
Health and Welfare Cash Value (4)	85,527	123,431	72,175	1,611	110,717
Perquisites	8,500	8,500	8,500	--	8,500
Separation Payments					
Excise Tax & Gross-Up (5)	5,020,003	2,029,702	--	--	1,752,663
Separation Payment for Non-Compete Agreement	1,974,616	716,323	762,458	443,769	630,703
Separation Payment for Liquidated Damages	3,949,232	1,432,646	762,458	443,769	1,261,405
Total	**$32,013,655**	**$8,321,406**	**$7,139,377**	**$4,611,013**	**$7,625,711**

(1) All Named Executive Officers would receive a payout under the 2007 Annual Incentive Program and the 2005 – 2007 Performance Cash Program based on actual results. Under the terms of the 2006 – 2008 and 2007 – 2009 Performance Cash Programs, participants who are terminated upon a Change of Control become eligible for immediate payout of a target award, and under the terms of the outstanding grants of restricted shares and RSUs, all unvested shares and share units held by participants terminated upon a Change of Control would be immediately vested and paid.

(2) Employment agreements with Messrs. Shivery, McHale and Butler provide for the addition of three years of age and service in the calculation of pension benefits available upon termination following a Change of Control. For Mr. Shivery, these three years of added age and service are in addition to the three years of added service provided upon his voluntary termination. Pension amounts reflected in the table are present values at the end of 2007 of benefits payable to each Named Executive Officer at the earliest unreduced benefit age (Mr. Shivery: age 62; Mr. McHale: age 62; Mr. Olivier: age 58; Mr. Necci: age 55; and Mr. Butler: age 62). All but the benefit payable to Mr. Olivier are annuities that are calculated using the assumptions detailed in the notes to the Pension Benefits Table. Mr. Olivier's benefit would be paid as a lump sum of $2,050,000 as offset by benefits from the Retirement Plan.

(3) The deferred compensation values are vested balances for all Named Executive Officers since all unvested matching contribution would become fully vested upon the occurrence of a change of control.

(4) Employment agreements with Messrs. Shivery, McHale and Butler provide for the payment of three years of active health benefits value and retiree health benefits if adding the three years of age and service would have made the executive eligible under the Retirement Plan. Messrs. Olivier and Necci participate in the SSP and are eligible for two years of active health benefits continuation. Six months of company-paid COBRA benefits are generally made available to all employees whose employment terminates involuntarily without cause. As a result, the amounts reported in the table represent the cash value of 30 months of employer contributions for each Named Executive Officer except Mr. Olivier, whose benefits would consist of the cash value of 18 months of employer contributions. Mr. Necci is eligible to retire and would therefore receive retiree benefits. In addition to continuation of active health benefits, retiree health benefits f or Messrs. Shivery and Olivier, which are provided for in each of their respective employment agreements regardless of eligibility, would be paid as a lump sum and grossed up for applicable withholding taxes. With the exception of Mr. Necci, all Named Executive Officers are also eligible to receive reimbursement of fees for financial planning and tax preparation services for three years.

(5) Excise Tax gross-up: Upon a Change of Control, employees may be subject to certain excise taxes under Section 280G of the Internal Revenue Code. Employment agreements with each Named Executive Officer except Messrs. Olivier and Necci provide for a grossed-up reimbursement of these excise taxes. The amounts in the table are based on a Section 280G excise tax rate of 20%, a statutory federal income tax withholding rate of 35%, a Connecticut state income tax rate of 5%, and a Medicare tax rate of 1.45%. Mr. Olivier's and Mr. Necci’s benefits through the SSP do not provide for this payment. Severance Payments: Employment agreements with each NEO except Messrs. Olivier and Necci provide for a severance payment equal to three-times

base salary plus annual incentives at target, one multiple of which is associated with the execution of a written non-competition agreement. Mr. Olivier's and Mr. Necci's benefits under the SSP would consist of a payment of two-times base salary plus target annual incentives, all of which is conditioned upon the execution of a written non-competition agreement.

Cheryl W. Grisé

The following table sets forth the payments to be received by Cheryl Grisé, former chief executive officer of CL&P and former executive vice president of NU, following her retirement from NU on July 1, 2007. At the time Mrs. Grisé announced her intention to retire, NU entered into an agreement in principle with her to ensure that she would remain with NU until at least July 1, 2007. Under the agreement in principle, on January 2, 2008, NU paid Mrs. Grisé a lump sum cash payment of $120,535 (i) as consideration for a standard general release of all claims against NU in connection with her employment, which she delivered to NU upon her retirement, and (ii) in lieu of a grant of RSUs and/or performance cash under the 2007-2009 long-term incentive program. Because Mrs. Grisé retired, she is also entitled to receive a payment under the 2007 Annual Incentive Program. In addition, as set forth in the notes to the Grants of Plan-Based Awards Table, Mrs. Gri sé is eligible for distributions in the first quarter of 2008 under the 2005-2007 Performance Cash Program based on goal achievement, prorated to reflect that Mrs. Grisé performed services for two and one-half years out of the three-year period, and an award under the 2006-2008 Performance Cash Program based on goal achievement, prorated to reflect that Mrs. Grisé performed services for one and one-half years out of the three-year period ending December 31, 2008. Mrs. Grisé's unvested RSUs from grants made in 2004, 2005, and 2006 were prorated based on service during 2007, and the remainder were forfeited. Mrs. Grisé is entitled to all of her vested but deferred RSUs, and she is eligible for a vested benefit under the Retirement Plan and the SERP.

Post-Employment Compensation: Cheryl W. Grisé

Payment	**($)**
Incentive Programs (1)	
Annual Incentive	187,645
Performance Cash Program	711,994
Restricted Stock and RSUs	778,742
Pension and Deferred Compensation (2)	
Qualified Retirement Plan	28,525
Supplemental Plan Payments	--
Special Retirement Benefits	--
Other Benefits (3)	
Health and Welfare Cash Value	--
Separation Payments (4)	
Separation Payment for Non-Compete Agreement	120,535
Separation Payment for Liquidated Damages	--
Total	1,827,441

(1) Upon retirement, Mrs. Grisé became eligible to receive a payout under the 2007 Annual Incentive Program. She is also eligible to receive prorated payouts under the 2005-2007 and 2006-2008 Performance Cash Programs, which will be paid in 2008 and 2009, respectively, based on final performance. Amounts reflected in the table are actual payouts for the 2005-2007 Performance Cash Program and estimated payouts based on target performance for the 2006-2008 Performance Cash Program. Upon Mrs. Grisé's retirement on July 1, 2007, unvested RSUs were vested in proportion to the time she was employed with NU in 2007. Under the terms of the long-term incentive programs in which Mrs. Grisé participated, the remaining unvested RSUs were forfeited. A total of 24,872 RSUs vested and 19,373 RSUs were forfeited. On January 4, 2008, NU distributed to Mrs. Grisé 17,361 common shares in respect of all previously vested RSUs (for which distribution of common shares had been deferred) following a six-month delay required for deferred compensation paid to "key employees" under Section 409A of the Internal Revenue Code, and NU withheld 7,511 shares to satisfy Mrs. Grisé's tax obligations. Mrs. Grisé realized $778,743 in ordinary income as a result of this transaction.

(2) Pension values are the total accrued pension benefit payable as an annuity that pays 75% to her surviving spouse. At the time of her retirement, Mrs. Grisé began receiving her qualified retirement benefit. In compliance with Section 409A of the Internal Revenue Code, NU delayed the start of Mrs. Grisé's SERP payments until six months after her retirement. On January 2, 2008, NU paid six-months of Mrs. Grisé's SERP "make-whole" benefit ($134,046) and six months of the SERP "target" benefit ($155,155). Mrs. Grisé's monthly SERP "make-whole" and "target" benefits are $21,693 and $25,109, respectively. Assumptions used in the calculation of this benefit are further discussed in the notes to the Pension Benefits table.

(3) Under the Retirement Plan, Mrs. Grisé became eligible to receive health benefits upon retirement. Mrs. Grisé did not receive any health and welfare benefits in excess of the benefits NU offers to all of its employees.

(4) In lieu of participation in the 2007-2009 Long-Term Incentive Program, Mrs. Grisé's agreement in principle provides for a lump sum payment in the amount of $120,535, which NU paid to her six months after her retirement on January 2, 2008.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

NU

Incorporated herein by reference is the information contained in the sections "Common Share Ownership of Certain Beneficial Owners" and "Common Share Ownership of Trustees and Management" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, expected to be dated March 31, 2008, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

Certain information required by this Item 12 has been omitted for PSNH and WMECO pursuant to Instruction I(2) (c) to Form 10-K, Omission of Information by Certain Wholly-Owned Subsidiaries.

CL&P

NU owns 100% of the outstanding common stock of CL&P. The following table sets forth, as of February 28, 2008, the beneficial ownership of the equity securities of NU by (i) the Chief Executive Officer of CL&P and the directors and executive officers of CL&P listed on the Summary Compensation Table in Item 11 and (ii) all of the current executive officers and directors of CL&P, as a group. No equity securities of CL&P are owned by any of the directors and executive officers of CL&P.

	Amount and Nature of Beneficial Ownership (1)				
Name	Shares	Options (2)	Total	Percent of Class	Restricted Share Units (3)
Leon J. Olivier, CEO, Director	18,205 (5)	0	18,205	*	45,199
David R. McHale, CFO, Director	13,092 (5)(6)(7)	0	13,092	*	42,107
Gregory B. Butler, Senior Vice President and General Counsel	27,633 (4)(5)(6)	0	27,633	*	43,172
Raymond P. Necci, President, COO, Director	19,151 (5)(6)(7)	0	19,151	*	17,251
Charles W. Shivery, Director	47,068 (5)(8)	29,024	76,092	*	312,442
Cheryl W. Grisé, former chief executive officer – CL&P	74,330 (5)(7)(9)	0	74,330	*	1,901
All directors and Executive Officers as a Group (8 persons)	215,822	37,424	253,246	*	479,451

* Less than 1% of common shares outstanding.

(1) The persons named in the table have sole voting and investment power with respect to all shares beneficially owned by each of them, except as noted below.

(2) Reflects common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 28, 2008.

(3) Includes unissued common shares consisting of restricted share units and deferred restricted share units as to which none of the Directors or Named Executive Officers has voting or investment power. Also includes "phantom" common shares representing employer matching contributions, distributable only in cash held by individuals who participate in the NU Deferred Compensation Plan for Executives. Accordingly, these securities have been excluded from the "Total" column.

(4) Includes 24,850 shares owned jointly by Mr. Butler and his wife with whom he shares voting and investment power.

(5) Includes common shares held in a 401k Plan for the Employee Stock Ownership Plan Account over which the holder has sole voting and no investment power (Mr. Butler: 2,388 shares; Mr. McHale: 3,014 shares; Mr. Necci: 3,125 shares; Mr. Olivier: 1,150 shares; Mrs. Grisé: 3,967 shares; and Mr. Shivery: 1,304 shares).

(6) Includes common shares held in a 401k Plan NU Common Shares Fund over which the holder has sole voting and no investment power (Mr. Butler: 395 shares, Mr. McHale: 1,445 shares and Mr. Necci: 228 shares).

(7) Includes common shares held in a 401k Plan TRAESOP/PAYSOP account over which the holder has sole voting and no investment power (Mr. McHale: 100 shares, Mr. Necci: 1,913 shares and Mrs. Grisé: 778 shares).

(8) Includes 1,500 shares owned jointly by Mr. Shivery and his wife with whom he shares voting and investment power.

(9) Includes 265 shares held by Mrs. Grisé's husband as custodian for their children. Mrs. Grisé and her husband share voting and investment power with respect to these 265 shares. Mrs. Grisé resigned as Chief Executive Officer of CL&P on January 15, 2007 and retired from NU on July 1, 2007.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth the number of our common shares issuable under our equity compensation plans, as well as their weighted exercise price, in accordance with the rules of the SEC:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,160,360[(a)]	18.34[(b)]	4,096,447[(c)]
Equity compensation plans not approved by security holders	0[(d)]	0	0
Total	1,160,360	18.34	4,096,447

(a) Includes 397,180 common shares to be issued upon exercise of options, and 763,180 common shares for distribution of restricted share units pursuant to the terms of our Incentive Plan.

(b) The weighted-average exercise price in Column (b) does not take into account restricted share units, which have no exercise price.

(c) Includes 1,041,364 common shares issuable under our Employee Share Purchase Plan II.

(d) All of our current compensation plans under which equity securities of NU are authorized for issuance have been approved by our shareholders.

Item 13. Certain Relationships and Related Transactions, and Trustee Independence

Incorporated herein by reference is the information contained in the sections captioned "Trustee Independence" and "Certain Relationships and Related Transactions" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, expected to be dated March 31, 2008, which will be filed with the Securities and Exchange Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

The Directors of CL&P are employees of CL&P and/or other subsidiaries of NU and thus are not considered independent under the NYSE guidelines discussed under "Trustee Independence" in the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, to be dated March 31, 2008, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

Certain information required by this Item 13 has been omitted for PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly-Owned Subsidiaries.

Item 14. Principal Accountant Fees and Services

NU

Incorporated herein by reference is the information contained in the section "Relationship with Independent Auditors" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, to be dated March 31, 2008, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

CL&P, PSNH, WMECO

None of CL&P, PSNH and WMECO is subject to the audit committee requirements of the SEC, the national securities exchanges or the national securities associations. CL&P, PSNH and WMECO obtain audit services from the independent auditor engaged by the Audit Committee of NU's Board of Trustees. The NU Audit Committee has established policies and procedures regarding the pre-approval of services provided by the principal auditors. Those policies and procedures delegate pre-approval of services to the NU Audit Committee Chair and/or Vice Chair provided that such offices are held by Trustees of NU who are "independent" within the meaning of the Sarbanes-Oxley Act of 2002 and that all such pre-approvals are presented to the NU Audit Committee at the next regularly scheduled meeting of the NU Audit Committee.

The following relates to fees and services for the entire NU system, including CL&P, PSNH, and WMECO:

Fees Paid to Principal Auditor

We paid Deloitte & Touche LLP fees aggregating $3,108,754 and $3,134,359 for the years ended December 31, 2007 and 2006, respectively, comprised of the following:

1. Audit Fees

The aggregate fees billed to us and our subsidiaries by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu and their respective affiliates (collectively, the Deloitte Entities), for audit services rendered for the years ended December 31, 2007 and 2006 totaled $2,789,900 and $2,938,255, respectively. The audit fees were incurred for audits of our annual consolidated financial statements and those of our subsidiaries, reviews of financial statements included in our Quarterly Reports on Form 10-Q and those of our subsidiaries, comfort letters, consents and other costs related to registration statements and financings. The fees also included audits of internal controls over financial reporting as of December 31, 2007 and 2006.

2. Audit Related Fees

The aggregate fees billed to us and our subsidiaries by the Deloitte Entities for audit related services rendered for the years ended December 31, 2007 and 2006 totaled $260,000 and $150,000, respectively, primarily related to the examination of management’s assertions about the securitization subsidiaries of CL&P, PSNH and WMECO and about our 401k Plan.

3. Tax Fees

The aggregate fees billed to us and our subsidiaries by the Deloitte Entities for tax services for the years ended December 31, 2007 and 2006 totaled $57,354 and $44,604, respectively. These services related solely to reviews of tax returns. There were no services related to tax advice or tax planning.

4. All Other Fees

The aggregate fees billed to us and our subsidiaries by the Deloitte Entities for services other than the services described above totaled $1,500 for each of the years ended December 31, 2007 and 2006 consisting of a license fee for access to an accounting research database.

The NU Audit Committee pre-approves all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed for us by our independent auditors, subject to the de minimis exceptions for non-audit services described in Section 10A(i)(1)(B) of the Securities Exchange Act of 1934, which are approved by the NU Audit Committee prior to the completion of the audit. The NU Audit Committee may form and delegate its authority to subcommittees consisting of one or more members when appropriate, including the authority to grant pre-approvals of audit and permitted non-audit services, provided that decisions of such subcommittee to grant pre-approvals are presented to the full NU Audit Committee at its next scheduled meeting. During 2007, the only services provided by the Deloitte Entities that were not pre-approved by the Audit Committee were de minimis services related to the issuance of an agreed-upon procedu res report in connection with a debt financing transaction by PSNH for which the Deloitte Entities received a fee of $5,000. The Audit Committee approved these de minimis services prior to the completion of the audit. The Deloitte Entities did not provide any other services that were not pre-approved by the Audit Committee.

The NU Audit Committee has considered whether the provision by the Deloitte Entities of the non-audit services described above was allowed under Rule 2-01(c)(4) of Regulation S-X and was compatible with maintaining auditor independence and has concluded that the Deloitte Entities were and are independent of us in all respects.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements:

The Reports of the Independent Registered Public Accounting Firm and financial statements of CL&P, PSNH and WMECO are hereby incorporated by reference and made a part of this report (see "Item 8. Financial Statements and Supplementary Data").

Report of Independent Registered Public Accounting Firm	S-1

2. Schedules:

Financial Statement Schedules for NU (Parent), NU and Subsidiaries, CL&P and Subsidiaries, PSNH and Subsidiaries, and WMECO and Subsidiary are listed in the Index to Financial Statement Schedules	S-2
3. Exhibit Index	E-1

SIGNATURES

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

NORTHEAST UTILITIES
(Registrant)

By	/s/ Charles W. Shivery Charles W. Shivery Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	Date February 28, 2008

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

Signature	Title	Date
/s/ Charles W. Shivery Charles W. Shivery	Chairman of the Board, President and Chief Executive Officer, and a Trustee (Principal Executive Officer)	February 28, 2008
/s/ David R. McHale David R. McHale	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2008
/s/ Shirley M. Payne Shirley M. Payne	Vice President - Accounting and Controller	February 28, 2008
/s/ Richard H. Booth Richard H. Booth	Trustee	February 28, 2008
/s/ Cotton M. Cleveland Cotton M. Cleveland	Trustee	February 28, 2008
/s/ Sanford Cloud, Jr. Sanford Cloud, Jr.	Trustee	February 28, 2008
/s/ James F. Cordes James F. Cordes	Trustee	February 28, 2008
/s/ E. Gail de Planque E. Gail de Planque	Trustee	February 28, 2008
/s/ John G. Graham John G. Graham	Trustee	February 28, 2008
/s/ Elizabeth T. Kennan Elizabeth T. Kennan	Trustee	February 28, 2008

/s/ Kenneth R. Leibler Kenneth R. Leibler	Trustee	February 28, 2008
/s/ Robert E. Patricelli Robert E. Patricelli	Trustee	February 28, 2008
/s/ John F. Swope John F. Swope	Trustee	February 28, 2008

SIGNATURES

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

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

By	/s/ Leon J. Olivier	Date
	Leon J. Olivier	
	Chief Executive Officer	February 28, 2008
	(Principal Executive Officer)	

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

Signature	Title	Date
/s/ Charles W. Shivery Charles W. Shivery	Chairman and a Director	February 28, 2008
/s/ Leon J. Olivier Leon J. Olivier	Chief Executive Officer and a Director (Principal Executive Officer)	February 28, 2008
/s/ Raymond P. Necci Raymond P. Necci	President and Chief Operating Officer and a Director	February 28, 2008
/s/ David R. McHale David R. McHale	Senior Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 28, 2008
/s/ Shirley M. Payne Shirley M. Payne	Vice President - Accounting and Controller	February 28, 2008

SIGNATURES

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
(Registrant)

By	/s/ Leon J. Olivier Leon J. Olivier Chief Executive Officer (Principal Executive Officer)	Date February 28, 2008

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

Signature	Title	Date
/s/ Charles W. Shivery Charles W. Shivery	Chairman and a Director	February 28, 2008
/s/ Leon J. Olivier Leon J. Olivier	Chief Executive Officer and a Director (Principal Executive Officer)	February 28, 2008
/s/ Gary A. Long Gary A. Long	President and Chief Operating Officer and a Director	February 28, 2008
/s/ David R. McHale David R. McHale	Senior Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 28, 2008
/s/ Shirley M. Payne Shirley M. Payne	Vice President - Accounting and Controller	February 28, 2008

SIGNATURES

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY
(Registrant)

By	/s/ Leon J. Olivier	Date
	Leon J. Olivier	
	Chief Executive Officer	February 28, 2008
	(Principal Executive Officer)	

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

Signature	Title	Date
/s/ Charles W. Shivery Charles W. Shivery	Chairman and a Director	February 28, 2008
/s/ Leon J. Olivier Leon J. Olivier	Chief Executive Officer and a Director (Principal Executive Officer)	February 28, 2008
/s/ Rodney O. Powell Rodney O. Powell	President and Chief Operating Officer and a Director	February 28, 2008
/s/ David R. McHale David R. McHale	Senior Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 28, 2008
/s/ Shirley M. Payne Shirley M. Payne	Vice President - Accounting and Controller	February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities and the Boards of Directors of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company:

We have audited the consolidated financial statements of Northeast Utilities and subsidiaries (the "Company"), as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and the Company's internal control over financial reporting as of December 31, 2007, and have issued our report thereon dated February 28, 2008 (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, as of January 1, 2007); such consolidated financial statements and report are included in Northeast Utilities' 2007 Annual Report to Shareholders and are incorporated herein by reference.

We have also audited the consolidated financial statements of The Connecticut Light and Power Company ("CL&P"), Public Service Company of New Hampshire ("PSNH") and Western Massachusetts Electric Company ("WMECO") as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and have issued our reports thereon dated February 28, 2008 (which reports express unqualified opinions and include explanatory paragraphs regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, as of January 1, 2007); such consolidated financial statements and reports are included in CL&P's, PSNH's, and WMECO's 2007 Annual Reports and are incorporated herein by reference.

Our audits also included the consolidated financial statement schedules of the Company, CL&P, PSNH and WMECO, listed in Item 15. These consolidated financial statement schedules are the responsibility of the managements of the Company, CL&P, PSNH and WMECO. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements for each company taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
February 28, 2008

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All other schedules of the companies' for which provision is made in the applicable regulations of the SEC are not required under the related instructions or are not applicable, and therefore have been omitted.

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
BALANCE SHEETS
AT DECEMBER 31, 2007 AND 2006
(Thousands of Dollars)

	2007	2006
ASSETS		
Current Assets:		
Cash	$ 294	$ 1,791
Notes receivable from affiliated companies	115,600	915,900
Notes and accounts receivable	452	696
Accounts receivable from affiliated companies	4,690	3,540
Taxes receivable	6,971	-
Derivative assets - current	5,133	-
Prepayments	119	122
	133,259	922,049
Deferred Debits and Other Assets:		
Investments in subsidiary companies, at equity	3,235,694	2,520,144
Accumulated deferred income taxes	21,058	-
Other	18,153	19,547
	3,274,905	2,539,691
Total Assets	$ 3,408,164	$ 3,461,740
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 42,000	$ -
Long-term debt - current portion	150,000	-
Accounts payable	27	310
Accounts payable to affiliated companies	1,743	14
Accrued taxes	-	240,466
Accrued interest	5,180	5,179
Other	425	870
	199,375	246,839
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	-	1,685
Derivative liabilities - long-term	-	6,483
Other	27,811	2,136
	27,811	10,304
Capitalization:		
Long-Term Debt	267,143	406,418
Common shares, $5 par value - authorized 225,000,000 shares; 175,924,694 shares issued and 155,079,770 shares outstanding in 2007 and 175,420,239 shares issued and 154,233,141 shares outstanding in 2006	879,623	877,101
Capital surplus, paid in	1,465,946	1,449,586
Deferred contribution plan - employee stock ownership plan	(26,352)	(34,766)
Retained earnings	946,792	862,660
Accumulated other comprehensive income	9,359	4,498
Treasury stock, 19,705,545 shares in 2007 and 19,684,249 shares in 2006	(361,533)	(360,900)
Common Shareholders' Equity	2,913,835	2,798,179
Total Capitalization	3,180,978	3,204,597
Total Liabilities and Capitalization	$ 3,408,164	$ 3,461,740

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF INCOME/(LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005
(Thousands of Dollars, Except Share Information)

	2007	2006	2005
Operating Revenues	$ -	$ -	$ -
Operating Expenses:			
Other	3,786	4,063	7,955
Operating Loss	(3,786)	(4,063)	(7,955)
Interest Expense	27,993	32,945	33,068
Other Income:			
Equity in earnings/(losses) of subsidiaries	247,786	473,279	(240,179)
Other, net	30,516	29,493	17,218
Other Income/(Loss), Net	278,302	502,772	(222,961)
Income/(Loss) Before Income Tax Expense/(Benefit)	246,523	465,764	(263,984)
Income Tax Expense/(Benefit)	40	(4,814)	(10,496)
Net Income/(Loss)	$ 246,483	$ 470,578	$ (253,488)
Basic Earnings/(Loss) Per Common Share	$ 1.59	$ 3.06	$ (1.93)
Fully Diluted Earnings/(Loss) Per Common Share	$ 1.59	$ 3.05	$ (1.93)
Basic Common Shares Outstanding (weighted average)	154,759,727	153,767,527	131,638,953
Fully Diluted Common Shares Outstanding (weighted average)	155,304,361	154,146,669	131,638,953

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005
(Thousands of Dollars)

	2007	2006	2005
Operating Activities:			
Net income/(loss)	$ 246,483	$ 470,578	$ (253,488)
Adjustments to reconcile to net cash flows (used in)/provided by operating activities:			
Equity in (earnings)/losses of subsidiaries	(247,786)	(473,279)	240,179
Cash dividends received from subsidiaries	141,891	190,759	142,709
Deferred income taxes	(14,324)	11,582	(13,563)
Other non-cash adjustments	13,006	13,903	9,857
Other sources of cash	1,831	1,064	2,900
Other uses of cash	-	(9,170)	(405)
Changes in current assets and liabilities:			
Receivables, net	(906)	4,285	(5,436)
Other current assets	3	14	(20)
Accounts payable	1,446	(448)	(250)
Taxes (receivable)/accrued	(244,675)	228,363	18,394
Other current liabilities	(444)	214	(287)
Net cash flows (used in)/provided by operating activities	(103,475)	437,865	140,590
Investing Activities:			
Investment in subsidiaries	(683,427)	(156,577)	(255,650)
Return of investment in subsidiaries	19,869	435,000	-
Decrease/(increase) in NU Money Pool lending	829,800	(563,200)	(142,100)
Other investing activities	1,462	2,185	2,572
Net cash flows provided by/(used in) investing activities	167,704	(282,592)	(395,178)
Financing Activities:			
Issuance of common shares	9,056	9,494	450,827
Increase/(decrease) in short-term debt	42,000	(32,000)	(68,000)
Retirements of long-term debt	-	(21,000)	(26,000)
Cash dividends on common shares	(120,988)	(112,745)	(87,554)
Other financing activities	4,206	2,379	(14,539)
Net cash flows (used in)/provided by financing activities	(65,726)	(153,872)	254,734
Net (decrease)/increase in cash	(1,497)	1,401	146
Cash - beginning of year	1,791	390	244
Cash - end of year	$ 294	$ 1,791	$ 390
Supplemental Cash Flow Information:			
Cash paid/(received) during the year for:			
Interest, net of amounts capitalized	$ 25,580	$ 32,498	$ 32,765
Income taxes	$ 259,707	$ (651)	$ 39,101

Schedule II

Northeast Utilities and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2007
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 22,369	$ 29,140	$ (7,106) (a)	$ 18,874 (b)	$ 25,529
Reserves not applied against assets:					
Operating reserves	$ 63,508	$ 15,080	$ -	$ 13,423 (c)	$ 65,165

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries. In November of 2006, the DPUC issued an order allowing CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2007, CL&P and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $24 million and $8 million, respectively.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith. This amount also includes a reduction to environmental reserves related to Mt. Tom generating plant (Mt. Tom) property that was sold to ECP in 2006.

Schedule II

Northeast Utilities and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2006
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts (d)	$ 25,044	$ 29,366	$ 1,922 (a)	$ 33,963 (b)	$ 22,369
Reserves not applied against assets:					
Operating reserves	$ 68,078	$ 27,550	$ -	$ 32,121 (c)	$ 63,508

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries. In November of 2006, the DPUC issued an order allowing CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2006, CL&P and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $17 million and $8 million, respectively.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith. This amount also includes a reduction to environmental reserves related to Mt. Tom property that was sold to ECP in 2006.

(d) Amounts include activity related to accounts that are classified as assets held for sale and discontinued operations.

Schedule II

Northeast Utilities and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2005
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts (d)	$ 25,325	$ 27,528	$ 975 (a)	$ 28,784 (b)	$ 25,044
Reserves not applied against assets:					
Operating reserves	$ 71,766	$ 22,359	$ -	$ 26,047 (c)	$ 68,078

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith. This amount also includes a reduction to environmental reserves related to land that was sold in 2005.

(d) Amounts include activity related to accounts that are classified as assets held for sale and discontinued operations.

Schedule II

The Connecticut Light and Power Company and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2007
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 1,679	$ 18,121	$ (8,243) (a)	$ 3,683 (b)	$ 7,874
Reserves not applied against assets:					
Operating reserves	$ 24,966	$ 9,584	$ -	$ 7,031 (c)	$ 27,519

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries and other adjustments. In November of 2006, the DPUC issued an order allowing CL&P to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2007, CL&P had uncollectible hardship accounts receivable reserves in the amount of $24 million.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

Schedule II

The Connecticut Light and Power Company and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2006
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 1,982	$ 13,582	$ 6,470 (a)	$ 20,355 (b)	$ 1,679
Reserves not applied against assets:					
Operating reserves	$ 25,155	$ 7,181	$ -	$ 7,370 (c)	$ 24,966

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries and other adjustments. In November of 2006, the DPUC issued an order allowing CL&P to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2006, CL&P had uncollectible hardship accounts receivable reserves in the amount of $17 million.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

Schedule II

The Connecticut Light and Power Company and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2005
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 2,010	$ 12,834	$ 605 (a)	$ 13,467 (b)	$ 1,982
Reserves not applied against assets:					
Operating reserves	$ 27,405	$ 8,385	$ -	$ 10,635 (c)	$ 25,155

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries and other adjustments.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith. This amount also includes a reduction to environmental reserves related to land that was sold in 2005.

Schedule II

Public Service Company of New Hampshire and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2007
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 2,626	$ 3,433	$ 324 (a)	$ 3,708 (b)	$ 2,675
Reserves not applied against assets:					
Operating reserves	$ 10,719	$ 1,666	$ -	$ 2,481 (c)	$ 9,904

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Public Service Company of New Hampshire and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2006
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 2,362	$ 4,208	$ 316 (a)	$ 4,260 (b)	$ 2,626
Reserves not applied against assets:					
Operating reserves	$ 10,777	$ 1,385	$ -	$ 1,443 (c)	$ 10,719

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Public Service Company of New Hampshire and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2005
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 1,764	$ 3,904	$ 252 (a)	$ 3,558 (b)	$ 2,362
Reserves not applied against assets:					
Operating reserves	$ 11,461	$ 1,890	$ -	$ 2,574 (c)	$ 10,777

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Western Massachusetts Electric Company and Subsidiary
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2007
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 5,073	$ 6,922	$ 155 (a)	$ 6,451 (b)	$ 5,699
Reserves not applied against assets:					
Operating reserves	$ 2,200	$ 1,669	$ -	$ 613 (c)	$ 3,256

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Western Massachusetts Electric Company and Subsidiary
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2006
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 3,653	$ 5,503	$ 194 (a)	$ 4,277 (b)	$ 5,073
Reserves not applied against assets:					
Operating reserves	$ 2,299	$ 987	$ -	$ 1,086 (c)	$ 2,200

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Western Massachusetts Electric Company and Subsidiary
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2005
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions - describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 2,563	$ 3,857	$ 37 (a)	$ 2,804 (b)	$ 3,653
Reserves not applied against assets:					
Operating reserves	$ 2,355	$ 836	$ -	$ 892 (c)	$ 2,299

(a) Amount relates to uncollectible amounts reserved for that relate to receivables other than those of customers.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

EXHIBIT INDEX

Each document described below is incorporated by reference by the registrant(s) listed to the files identified, unless designated with a (*), which exhibits are filed herewith.

Exhibit Number	Description
2	Plan of acquisition, reorganization, arrangement, liquidation or succession
(A)	NU
2.1	Amended and Restated Agreement and Plan of Merger (Exhibit 1, NU Form 8-K dated December 2, 1999, File No. 1-5324)
3	Articles of Incorporation and By-Laws
(A)	Northeast Utilities
3.1	Declaration of Trust of NU, as amended through May 10, 2005 (Exhibit A.1, NU Form U-1 dated June 23, 2005, File No. 70-10315)
(B)	The Connecticut Light and Power Company
3.1	Certificate of Incorporation of CL&P, restated to March 22, 1994 (Exhibit 3.2.1, 1993 CL&P Form 10-K, File No. 0-00404)
3.1.1	Certificate of Amendment to Certificate of Incorporation of CL&P, dated December 26, 1996 (Exhibit 3.2.2, 1996 CL&P Form 10-K, File No. 0-00404)
3.1.2	Certificate of Amendment to Certificate of Incorporation of CL&P, dated April 27, 1998 (Exhibit 3.2.3, 1998 CL&P Form 10-K, File No. 0-00404)
3.2	By-laws of CL&P, as amended to January 1, 1997 (Exhibit 3.2.3, 1996 CL&P Form 10-K, File No. 0-00404)
(C)	Public Service Company of New Hampshire
3.1	Articles of Incorporation, as amended to May 16, 1991. (Exhibit 3.3.1, 1993 PSNH Form 10-K, File No. 1-6392)
3.2	By-laws of PSNH, as in effect June 30, 2005 (Exhibit 3.2, PSNH Form 10-Q for the Quarter Ended June 30, 2005, File No. 1-6392)
(D)	Western Massachusetts Electric Company
3.1	Articles of Organization of WMECO, restated to February 23, 1995 (Exhibit 3.4.1, 1994 WMECO Form 10-K, File No. 0-7624)
3.2	By-laws of WMECO, as amended to April 1, 1999 (Exhibit 3.1, WMECO Form 10-Q for the Quarter Ended June 30, 1999, File No. 0-7624)
3.2.1	By-laws of WMECO, as further amended to May 1, 2000 (Exhibit 3.1, WMECO Form 10-Q for the Quarter Ended June 30, 2000, File No. 0-7624)
4	Instruments defining the rights of security holders, including indentures
(A)	Northeast Utilities
4.1	Rights Agreement dated as of February 23, 1999, between Northeast Utilities and Northeast Utilities Service Company, as Rights Agent (Exhibit 1, NU Registration Statement on Form 8-A, filed on April 12, 1999, File No. 001-05324)

4.1.1 Amendment to Rights Agreement (Exhibit 3, NU Form 8-K dated October 13, 1999, File No. 1-5324)

4.1.2 Second Amendment to Rights Agreement (Exhibit B-3, NU 35-CERT, dated February 1, 2002, File No. 070-09463)

4.2 Indenture dated as of April 1, 2002, between NU and the Bank of New York as Trustee (Exhibit A-3, NU 35-CERT filed April 9, 2002, File No. 70-9535)

4.2.1 First Supplemental Indenture dated as of April 1, 2002, between NU and the Bank of New York as Trustee, relating to $263M of Senior Notes, Series A, due 2012 (Exhibit A-4, NU 35-CERT filed April 9, 2002, File No. 70-9535)

4.2.2 Second Supplemental Indenture dated as of June 1, 2003, between NU and the Bank of New York as Trustee, relating to $150M of Senior Notes, Series B, due 2008. (Exhibit A-1.3 to NU 35-CERT filed June 6, 2003, File No. 70-10051)

4.3 Amended and Restated Credit Agreement dated December 9, 2005 between NU, the Banks Named Therein, Union Bank of California, N.A. as Administrative Agent, and Barclays Bank, PLC, JPMorgan Chase Bank, N.A. and Union Bank of California, N.A., as Fronting Banks (Exhibit 99.1, NU Form 8-K dated December 9, 2005, File No. 1-5324)

(B) The Connecticut Light and Power Company

4.1 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, Trustee, dated as of May 1, 1921 (Composite including all twenty-four amendments to May 1, 1967) (Exhibit 4.1.1, 1989 CL&P Form 10-K, File No. 0-00404)

4.1.1 Supplemental Indentures to the Composite May 1, 1921 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, dated as of October 1, 1994 (Exhibit 4.2.16, 1994 CL&P Form 10-K, File No. 0-00404)

4.1.2 Series A Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee, dated as of September 1, 2004 (Exhibit 99.2, CL&P Form 8-K filed September 22, 2004, File No. 0-00404)

4.1.3 Series B Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of September 1, 2004 (Exhibit 99.5, CL&P Form 8-K filed September 22, 2004, File No. 0-00404)

4.2 Composite Indenture of Mortgage and Deed of Trust between CL&P and Deutsche Bank Trust Company Americas f/k/a Bankers Trust Company, dated as of May 1, 1921, as amended and supplemented by seventy-three supplemental mortgages to and including Supplemental Mortgage dated as of April 1, 2005 (Exhibit 99.5, CL&P Form 8-K filed April 7, 2005, File No. 0-00404)

4.2.1 Supplemental Indenture (2005 Series A Bonds and 2005 Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of April 1, 2005 (Exhibit 99.2, CL&P Form 8-K filed April 13, 2005, File No. 0-00404)

4.2.2 Supplemental Indenture (2006 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of June 1, 2006 (Exhibit 99.2, CL&P Form 8-K filed June 7, 2006, File No. 0-00404)

4.2.3 Supplemental Indenture (2007 Series A Bonds and 2007 Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of March 1, 2007 (Exhibit 99.2, CL&P 8-K filed March 27, 2007, File No. 0-00404)

4.2.4 Supplemental Indenture (2007 Series C Bonds and 2007 Series D Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of September 1, 2006 (Exhibit 4, CL&P 8-K filed September 17, 2007, File No. 0-00404)

4.3 Financing Agreement between Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds, 1986 Series) dated as of December 1, 1986 (Exhibit C.1.47, 1986 NU Form U5S, File No. 30-246)

4.4 Financing Agreement between Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds, 1988 Series) dated as of October 1, 1988 (Exhibit C.1.55, 1988 NU Form U5S, File No. 30-246)

4.5 Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire, CL&P and the Trustee (Pollution Control Bonds, 1992 Series A) dated as of December 1, 1992 (Exhibit C.2.33, 1992 NU Form U5S, File No. 30-246)

4.6 Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993 (Exhibit 4.2.21, 1993 CL&P Form 10-K, File No. 0-00404)

4.7 Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Bonds - Series B, Tax Exempt Refunding) dated as of September 1, 1993 (Exhibit 4.2.22, 1993 CL&P Form 10-K, File No. 0-00404)

4.8 Amended and Restated Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Revenue Bond - 1996A Series) dated as of May 1, 1996 and Amended and Restated as of January 1, 1997 (Exhibit 4.2.24, 1996 CL&P Form 10-K, File No. 0-00404)

4.9 Amended and Restated Indenture of Trust between Connecticut Development Authority and the Trustee (CL&P Pollution Control Revenue Bond-1996A Series), dated as of May 1, 1996 and Amended and Restated as of January 1, 1997 (Exhibit 4.2.24.1, 1996 CL&P Form 10-K, File No. 0-00404)

4.10 AMBAC Municipal Bond Insurance Policy issued by the Connecticut Development Authority (CL&P Pollution Control Revenue Bond-1996A Series), effective January 23, 1997(Exhibit 4.2.24.3, 1996 CL&P Form 10-K, File No. 1-11419)

4.11 Compensation and Multiannual Mode Agreement among the Connecticut Development Authority and BNY Capital Markets, Inc. dated September 23, 2003 (Exhibit 4.2.7.5, CL&P Form 10-Q for the Quarter Ended September 30, 2003, File No. 0-00404)

4.12 Amended and Restated Receivables Purchase and Sale Agreement among CL&P and CL&P Receivables Corporation ("CRC") Corporate Asset Funding Company, Inc. ("CAFCO"), Citibank, N. A. ("Citibank") and Citicorp North America, Inc. ("CNAI"), dated as of March 30, 2001 (Exhibit 10.1, CL&P Form 10-Q for the Quarter Ended September 30, 2001, File No. 0-00404)

4.12.1 Amendment No. 2 to the Amended and Restated Receivables Purchase and Sale Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 10, 2002 (Exhibit 4.2.8.1, 2002 CL&P Form 10-K, File No. 0-00404)

4.12.2 Amendment No. 3 to the Amended and Restated Receivables Purchase and Sales Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 9, 2003 (Exhibit 4.2.8.2, CL&P Form 10-Q for the Quarter Ended September 30, 2003, File No. 0-00404)

4.12.3 Amendment No. 4 to the Amended and Restated Receivables Purchase and Sales Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 7, 2004 (Exhibit 4.12.3, CL&P Form 10-Q for the Quarter Ended June 30, 2005, File No. 0-00404)

4.12.4 Amendment No. 5 to the Amended and Restated Receivables Purchase and Sales Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 7, 2005 (Exhibit 4.12.4, CL&P Form 10-Q for the Quarter Ended June 30, 2005, File No. 0-00404)

4.12.5 Amendment No. 6 to the Amended and Restated Receivables Purchase and Sales Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 5, 2006 (Exhibit 4.12.5, CL&P Form 10-Q for the Quarter Ended June 30, 2006 File No. 0-00404)

4.12.6 Letter Amendment dated July 21, 2006 to Amended and Restated Receivables Purchase and Sales Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 5, 2006 (Exhibit 4.12.6, CL&P Form 10-Q for the Quarter Ended September 30, 2006, File No. 0-00404)

4.12.7 Amendment No. 7 to the Amended and Restated Receivables Purchase and Sales Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 3, 2007 (Exhibit 4, CL&P Form 10-Q for the Quarter Ended June 30, 2007, File No. 0-00404)

4.13 Purchase and Contribution Agreement between CL&P and CRC, dated as of September 30, 1997 (Exhibit 10.49, 1997 CL&P Form 10-K, File No. 0-00404)

4.13.1 Amendment No. 1 to the Purchase and Contribution Agreement between CL&P and CRC dated as of March 30, 2001 (Exhibit 4.2.9, 2002 CL&P Form 10-K, File No. 0-00404)

4.13.2 Amendment No. 3 to the Purchase and Contribution Agreement between CL&P and CRC dated as of July 7, 2004 (Exhibit 4.13.2, 2006 CL&P Form 10-K, File No. 0-00404)

4.14 Amended and Restated Credit Agreement dated December 9, 2005 between CL&P, WMECO, Yankee Gas and PSNH, the Banks Named Therein, and Citicorp USA, Inc., as Administrative Agent (Exhibit 99.2, CL&P Form 8-K dated December 9, 2005, File No. 0-00404)

(C) Public Service Company of New Hampshire

4.1 First Mortgage Indenture dated as of August 15, 1978 between PSNH and First Fidelity Bank, National Association, New Jersey, now First Union National Bank, Trustee, (Composite including all amendments to May 16, 1991) (Exhibit 4.4.1, 1992 PSNH Form 10-K, File No. 1-6392)

4.1.1 Tenth Supplemental Indenture dated as of May 1, 1991 between PSNH and First Fidelity Bank, National Association, now First Union National Bank (Exhibit 4.1, PSNH Form 8-K dated February 10, 1992, File No. 1-6392)

4.1.2 Twelfth Supplemental Indenture dated as of December 1, 2001 between PSNH and First Union National Bank (Exhibit 4.3.1.2, 2001 PSNH Form 10-K, File No. 1-6392)

4.1.3 Thirteenth Supplemental Indenture, dated as of July 1, 2004, between PSNH and Wachovia Bank, National Association, successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee (Exhibit 99.2, PSNH Form 8-K filed October 5, 2004, File No. 1-6392)

4.1.4 Fourteenth Supplemental Indenture, dated as of October 1, 2005, between PSNH and Wachovia Bank, National Association successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee (Exhibit 99.2, PSNH Form 8-K filed October 6, 2005, File No. 1-6392)

4.1.5 Fifteenth Supplemental Indenture, dated as of September 17, 2007, between PSNH and Wachovia Bank, National Association successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee (Exhibit 4.1, PSNH Form 8-K filed September 24, 2007, File No. 1-6392)

4.2 Series D (Tax Exempt Refunding) Amended and Restated PCRB Loan and Trust Agreement dated as of April 1, 1999 (Exhibit 4.3.6, 1999 PSNH Form 10-K, File No. 1-6392)

4.3 Series E (Tax Exempt Refunding) Amended and Restated PCRB Loan and Trust Agreement dated as of April 1, 1999 (Exhibit 4.3.7, 1999 PSNH Form 10-K, File No. 1-6392)

4.4 Series A Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001 (Exhibit 4.3.4, 2001 PSNH Form 10-K, File No. 1-6392)

4.5 Series B Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001 (Exhibit 4.3.5, 2001 PSNH Form 10-K, File No. 1-6392)

4.6 Series C Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001 (Exhibit 4.3.6, 2001 PSNH Form 10-K, File No. 1-6392)

4.7 Amended and Restated Credit Agreement dated December 9, 2005 between CL&P, WMECO, Yankee Gas and PSNH, the Banks Named Therein, and Citicorp USA, Inc., as Administrative Agent (Exhibit 99.2, PSNH Form 8-K dated December 9, 2005, File No. 1-6392)

(D) Western Massachusetts Electric Company

4.1 Loan Agreement between Connecticut Development Authority and WMECO, (Pollution Control Revenue Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993 (Exhibit 4.4.13, 1993 WMECO Form 10-K, File No. 0-7624)

4.2 Indenture between WMECO and the Bank of New York, as Trustee, dated as of September 1, 2003 (Exhibit 99.2, WMECO Form 8-K filed October 8, 2003, File No. 0-7624)

4.2.1 First Supplemental Indenture between WMECO and the Bank of New York, as Trustee, dated as of September 1, 2003 (Exhibit 99.3, WMECO Form 8-K filed October 8, 2003, File No. 0-7624)

4.2.2 Second Supplemental Indenture dated as of September 1, 2004, between WMECO and Bank of New York, as Trustee (Exhibit 4.1, WMECO Form 8-K filed September 27, 2004, File No. 0-7624)

4.2.3 Third Supplemental Indenture between WMECO and The Bank of New York Trust, as Trustee, dated as of August 1, 2005 (Exhibit 4.1, WMECO Form 8-K filed August 12, 2005, File No. 0-7624)

4.2.4 Fourth Supplemental Indenture between WMECO and The Bank of New York Trust, as Trustee, dated as of August 1, 2007 (Exhibit 4.1, WMECO Form 8-K filed August 17, 2007, File No. 0-7624)

4.3 Amended and Restated Credit Agreement dated December 9, 2005 between CL&P, WMECO, Yankee Gas and PSNH, the Banks Named Therein, and Citicorp USA, Inc., as Administrative Agent (Exhibit 99.2, WMECO Form 8-K dated December 9, 2005, File No. 1-6392)

10 Material Contracts

(A) NU

10.1 Lease dated as of April 14, 1992 between The Rocky River Realty Company and Northeast Utilities Service Company with respect to the Berlin, Connecticut headquarters (Exhibit 10.29, 1992 NU Form 10-K, File No. 1-5324)

10.2 Indenture of Mortgage and Deed of Trust dated July 1, 1989 between Yankee Gas Services Company and the Connecticut National Bank, as Trustee (Exhibit 4.7, Yankee Energy System, Inc. Form 10-K for the fiscal year ended September 30, 1990, File No. 0-10721)

10.2.1 First Supplemental Indenture of Mortgage and of Trust dated April 1, 1992 between Yankee Gas Services Company and The Connecticut National Bank, as Trustee Yankee Energy System, Inc. (Registration Statement on Form S-3, dated October 2, 1992, File No. 33-52750)

10.2.2 Fourth Supplemental Indenture of Mortgage and Deed of Trust dated April 1, 1997 between Yankee Gas Services Company and Fleet National Bank (formerly The Connecticut National Bank), as Trustee (Exhibit 4.15, Yankee Energy System, Inc. Form 10-K for the fiscal year ended September 30, 1997, File No. 001-10721)

10.2.3 Fifth Supplemental Indenture of Mortgage and Deed of Trust dated January 1, 1999 between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) (Exhibit 4.2, Yankee Energy System, Inc. Form 10-Q for the fiscal quarter ended March 31, 1999, File No. 001-10721)

10.2.4 Sixth Supplemental Indenture and Deed of Trust dated January 1, 2004 between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) (Exhibit 10.5.6, 2004 NU Form 10-K, File No. 1-5324)

10.2.5 Seventh Supplemental Indenture and Deed of Trust dated November 1, 2004 between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) (Exhibit 10.5.7, 2004 NU Form 10-K, File No. 1-5324)

10.2.6 Eighth Supplemental Indenture and Deed of Trust dated July 1, 2005 between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly the Connecticut National Bank) (Exhibit 10.5.8, NU Form 10-Q for the Quarter Ended June 30, 2005, File No. 1-5324)

*10.3 Summary of Trustee Compensation Arrangement

10.4 Northeast Utilities Deferred Compensation Plan for Trustees, amended and restated effective January 1, 2004 (Exhibit 10.32, NU Form 10-Q for the Quarter Ended March 31, 2004, File No. 1-5324)

10.4.1 Amendment No. 3 to Northeast Utilities Deferred Compensation Plan for Trustees, effective January 1, 2005 (Exhibit 10.24.1, 2005 NU Form 10-K, File No. 1-5324)

10.4.2 Amendment No. 4 to Northeast Utilities Deferred Compensation Plan for Trustees, effective September 12, 2006 (Exhibit 10.5.2, 2006 NU Form 10-K, File No. 1-5324)

10.5 Purchase and Sale Agreement dated as of May 1, 2006 between Select Energy, Inc. and Amerada Hess Corporation (Exhibit 10.32, NU Form 10-Q for the Quarter Ended March 31, 2006, File No. 1-5324)

10.6 Purchase and Sale Agreement dated July 24, 2006 between HWP and Mt. Tom Generating Company LLC (Exhibit 10.33, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.6.1 Guaranty dated July 24, 2006 of NU for the benefit of Mt. Tom Generating Company LLC (Exhibit 10.33.2, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.7 Stock Purchase Agreement dated July 24, 2006 between NU Enterprises and NE Energy, Inc. (Exhibit 10.34, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.7.1 Guaranty dated July 24, 2006 of NU for the benefit of NE Energy, Inc. (Exhibit 10.34.2, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.8 Purchase and Sale Agreement dated July 24, 2006 by and among NGS, Select Energy, Northeast Utilities Service Company on the one hand, and NE Energy, Inc. on the other hand (Exhibit 10.35, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.8.1 Guaranty dated July 24, 2006 of NU for the benefit of NE Energy, Inc. (Exhibit 10.35.2, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.9 Stock Purchase Agreement dated as of February 1, 2006 by and among Ameresco, Inc. ("Ameresco"), NU Enterprises and NU (Exhibit 10.36, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.9.1 Stock Purchase Agreement Amendment and Waiver dated as of May 5, 2006 among NU Enterprises, NU and Ameresco (Exhibit 10.36.3, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.9.2 NU Indemnification Agreement dated as of May 5, 2006 (Exhibit 10.36.4, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.9.3 Agreement to Purchase Contract Payments dated as of May 5, 2006 among NU, Ameresco and General Electric Capital Corporation (Exhibit 10.36.5, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

(B) NU, CL&P, PSNH and WMECO

10.1 Service Contract dated as of July 1, 1966 between each of NU, CL&P and WMECO and Northeast Utilities Service Company (NUSCO) (Exhibit 10.20, 1993 NU Form 10-K, File No. 1-5324)

10.1.1 Form of Amendment and Renewal of Service Contract dated as of January 1, 2007 (Exhibit 10.2, 2006 NU Form 10-K, File No. 1-5324)

*10.1.2 Form of Amendment and Renewal of Service Contract dated as of January 1, 2008

10.2 Stockholder Agreement dated as of July 1, 1964 among the stockholders of Connecticut Yankee Atomic Power Company (CYAPC) (Exhibit 10.1, 1994 NU Form 10-K, File No. 1-5324)

10.3 Capital Funds Agreement dated as of September 1, 1964 between CYAPC and CL&P, HELCO, PSNH and WMECO (Exhibit 10.3, 1994 NU Form 10-K, File No. 1-5324)

10.4 Power Purchase Contract dated as of July 1, 1964 between CYAPC and each of CL&P, HELCO, PSNH and WMECO (Exhibit 10.2, 1994 NU Form 10-K, File No. 1-5324)

10.5 Additional Power Purchase Contract dated as of April 30, 1984, between CYAPC and each of CL&P, PSNH and WMECO (Exhibit 10.2.1, 1994 NU Form 10-K, File No. 1-5324)

10.6 Supplementary Power Contract dated as of April 1, 1987, between CYAPC and each of CL&P, PSNH and WMECO (Exhibit 10.2.6, 1987 NU Form 10-K, File No. 1-5324)

10.7 Form of 1996 Amendatory Agreement between CYAPC and CL&P dated December 4, 1996 (Exhibit 10 (B) 10.9, 2003 NU Form 10-K, File No. 1-5324)

10.7.1 Form of First Supplemental to the 1996 Amendatory Agreement dated as of February 10, 1997 (Exhibit 10 (B) 10.9.1, 2003 NU Form 10-K, File No. 1-5324)

10.8 Amended and Restated Additional Power Contract between CYAPC and purchasers named therein, dated as of April 30, 1984 and restated as of July 1, 2004) (Exhibit 10.9.3, 2004 NU Form 10-K, File No. 1-5324)

10.8.1 Revision to Attachment B to Amended and Restated Additional Power Contract, dated as of April 30, 1984, issued on August 15, 2007 and effective January 1, 2007 (as contained in Settlement Agreement dated August 15, 2006 among CYAPC, Connecticut Department of Public Utility Control, Connecticut Consumer Counsel, Maine Public Advocate and Maine Public Utility Commission, filed with the Federal Energy Regulatory Commission on August 15, 2006 in Dockets Nos. ER04-981-000 and EL04-109-000) (Exhibit 10.10.1, 2006 NU Form 10-K, File No. 1-5324)

10.9 2000 Amendatory Agreement between CYAPC and CL&P dated as of July 28, 2000 (Exhibit 10.9.2, 2004 NU Form 10-K, File No. 1-5324)

10.10 Stockholder Agreement dated December 10, 1958 between Yankee Atomic Electric Company (YAEC) and CL&P, HELCO, PSNH and WMECO (Exhibit 10.4, 1993 NU Form 10-K, File No. 1-5324)

10.11 Amended and Restated Power Purchase Contract dated as of April 1, 1985, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10.5, 1988 NU Form 10-K, File No. 1-5324)

10.11.1 Amendment No. 4 to Power Contract, dated May 6, 1988, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10.5.1, 1989 NU Form 10-K, File No. 1-5324)

10.11.2 Amendment No. 5 to Power Contract, dated June 26, 1989, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10.5.2, 1989 NU Form 10-K, File No. 1-5324)

10.11.3 Amendment No. 6 to Power Contract, dated July 1, 1989, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10.5.3, 1989 NU Form 10-K, File No. 1-5324)

10.11.4 Amendment No. 7 to Power Contract, dated February 1, 1992, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10.5.4, 1993 NU Form 10-K, File No. 1-5324)

10.11.5 Form of Amendment No. 8 to Power Contract, dated June 1, 2003, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10 (B) 10.11.5, 2003 NU Form 10-K, File No. 1-5324)

10.11.6 Form of Amendment No. 9 to Power Contract, dated November 17, 2005, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10.11.6, 2005 NU Form 10-K, File No. 1-5324)

10.11.7 Form of Amendment No. 10 to Power Contract, dated April 14, 2006 between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10.11.7, NU Form 10-Q for the Quarter Ended June 30, 2006, File No. 1-5324)

10.12 Stockholder Agreement dated as of May 20, 1968, among stockholders of MYAPC (Exhibit 10.6, 1997 NU Form 10-K, File No. 1-5324)

10.13 Capital Funds Agreement dated as of May 20, 1968 between MYAPC and CL&P, PSNH, HELCO and WMECO (Exhibit 10.8, 1997 NU Form 10-K, File No. 1-5324)

10.13.1 Amendment No. 1 to Capital Funds Agreement, dated as of August 1, 1985, between MYAPC, CL&P, PSNH and WMECO (Exhibit No. 10.8.1, 1994 NU Form 10-K, File No. 1-5324)

10.14 Power Purchase Contract dated as of May 20, 1968 between MYAPC and each of CL&P, HELCO, PSNH and WMECO (Exhibit 10.7, 1997 Form 10-K, File No. 1-5324)

10.14.1 Amendment No. 1 to Power Contract dated as of March 1, 1983 between MYAPC and each of CL&P, PSNH and WMECO (Exhibit 10.7.1, 1993 NU Form 10-K, File No. 1-5324)

10.14.2 Amendment No. 2 to Power Contract dated as of January 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO (Exhibit 10.7.2, 1993 NU Form 10-K, File No. 1-5324)

10.14.3 Amendment No. 3 to Power Contract dated as of October 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO (Exhibit No. 10.7.3, 1994 NU Form 10-K, File No. 1-5324)

10.15 Additional Power Contract dated as of February 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO (Exhibit 10.7.4, 1993 NU Form 10-K, File No. 1-5324)

10.16 1997 Amendatory Agreement dated as of August 6, 1997 between MYAPC and each of CL&P, PSNH and WMECO (Exhibit 10.14.5, 2005 NU Form 10-K, File No. 1-5324)

10.17 Composite Conformed Rate Schedule 2004 reflecting the operative provisions of: I. Additional Power Contract dated as of February 1, 1984, II. 1997 Amendatory Agreement dated as of August 6, 1997, III. Settlement Agreement in Docket No. ER-04-55-000 and IV. Formula Rate (Exhibit 10.19, 2006 NU Form 10-K, File No. 1-5324)

10.18 Agreements among New England Utilities with respect to the Hydro-Quebec interconnection projects (Exhibits 10(u) and 10(v); 10(w), 10(x), and 10(y), 1990 and 1988, respectively, Form 10-K of New England Electric System, File No. 1-3446.)

10.19 Transmission Operating Agreement dated as of February 1, 2005 between the Initial Participating Transmission Owners, Additional Participating Transmission Owners and ISO New England, Inc. (Exhibit 10.29, 2004 NU Form 10-K, File No. 1-5324)

10.19.1 Rate Design and Funds Disbursement Agreement, effective June 30, 2006 among the Initial Participating Transmission Owners, Additional Participating Transmission Owners and ISO New England, Inc. (Exhibit 10.22.1, 2006 NU Form 10-K, File No. 1-5324)

10.20 Employment Agreement with Cheryl W. Grisé, dated as of April 1, 2003 (Exhibit 10.45.6, NU Form 10-Q for Quarter Ended March 31, 2003, File No. 1-5324)

10.20.1 Terms of Separation arrangements for Cheryl W. Grisé (Exhibit 10.24.1, 2006 NU Form 10-K, File No. 1-5324)

*10.20.2 Separation Agreement with Cheryl W. Grisé, dated as of June 22, 2007

10.21 Employment Agreement with Charles W. Shivery dated as of March 31, 2005 (Exhibit 10.24.2, NU Form 10-Q for the Quarter Ended March 31, 2005, File No. 1-5324)

10.22 Employment Agreement with Gregory B. Butler, dated as of October 1, 2003 (Exhibit 10 (B) 10.31, 2003 NU Form 10-K, File No. 1-5324)

10.23 Employment Agreement with David R. McHale dated as of March 31, 2005 (Exhibit 10.30, NU Form 10-Q for the Quarter Ended March 31, 2005, File No. 1-5324)

10.24 Description of terms of employment of Leon J. Olivier (Exhibit 10 (C) 10.3, 2003 NU Form 10-K, File No. 1-5324)

10.25 NU Incentive Plan, effective as of January 1, 1998 (Exhibit 10.35.1, 1998 NU Form 10-K, File No. 1-5324)

10.25.1 Amendment to NU Incentive Plan, effective as of February 23, 1999 (Exhibit 10.35.1.1, 1998 NU Form 10-K, File No. 1-5324)

10.25.2 Amendment 2 to NU Incentive Plan, effective as of September 12, 2006 (Exhibit 10.29.2, 2006 NU Form 10-K, File No. 1-5324)

*10.26 Amended and Restated NU Incentive Plan, effective as of May 9, 2007

10.27 Supplemental Executive Retirement Plan for Officers of NU System Companies, Amended and Restated effective as of January 1, 1992 (Exhibit 10.45.1, NU Form 10-Q for the Quarter Ended June 30, 1992, File No. 1-5324)

10.27.1 Amendment 1 to Supplemental Executive Retirement Plan, effective as of August 1, 1993 (Exhibit 10.35.1, 1993 NU Form 10-K, File No. 1-5324)

10.27.2 Amendment 2 to Supplemental Executive Retirement Plan, effective as of January 1, 1994 (Exhibit 10.35.2, 1993 NU Form 10-K, File No. 1-5324)

10.27.3 Amendment 3 to Supplemental Executive Retirement Plan, effective as of January 1, 1996 (Exhibit 10.36.3, 1995 NU Form 10-K, File No. 1-5324)

10.27.4 Amendment 4 to Supplemental Executive Retirement Plan, effective as of February 26, 2002 (Exhibit 10.35.4, 2001 NU Form 10-K, File No. 1-5324)

10.27.5 Amendment 5 to Supplemental Executive Retirement Plan, effective as of November 1, 2001 (Exhibit 10.35.5, 2001 NU Form 10-K, File No. 1-5324)

10.27.6 Amendment 6 to Supplemental Executive Retirement Plan, effective as of December 9, 2003 (Exhibit 10 (B) 10.18.6, 2003 NU Form 10-K, File No. 1-5324)

10.27.7 Amendment 7 to Supplemental Executive Retirement Plan, effective as of February 1, 2005 (Exhibit 10.18.7, 2004 NU Form 10-K, File No. 1-5324)

10.27.8 Amendment 8 to Supplemental Executive Retirement Plan, effective as of January 1, 2006 (Exhibit 10.30.8, 2006 NU Form 10-K, File No. 1-5324)

*10.27.9 Amendment No. 9 to Supplemental Executive Retirement Plan, effective as of January 1, 1992

10.28 Trust under Supplemental Executive Retirement Plan dated May 2, 1994 (Exhibit 10.33, 2002 NU Form 10-K, File No. 1-5324)

10.28.1 First Amendment to Trust, effective as of December 10, 2002 (Exhibit 10 (B) 10.19.1, 2003 NU Form 10-K, File No. 1-5324)

10.29 Special Severance Program for Officers of NU System Companies, as adopted on July 15, 1998 (Exhibit 10.37, 1998 NU Form 10-K, File No. 1-5324)

10.29.1 Amendment to Special Severance Program, effective as of February 23, 1999 (Exhibit 10.37.1, 1998 NU Form 10-K, File No. 1-5324)

10.29.2 Second Amendment to Special Severance Program, effective as of September 14, 1999 (Exhibit 10.3, NU Form 10-Q for the Quarter Ended September 30, 1999, File No. 1-5324)

10.29.3 Amendment 3 to Special Severance Program, effective September 12, 2006 (Exhibit 10.32.3, 2006 NU Form 10-K, File No. 1-5324)

10.30 Northeast Utilities Deferred Compensation Plan for Executives, amended and restated effective January 1, 2004 (Exhibit 10.33, NU Form 10-Q for the Quarter Ended March 31, 2004, File No 1-5324)

10.30.1 Amendment No. 1 to Northeast Utilities Deferred Compensation Plans for Executives, effective January 1, 2005 (Exhibit 10.25.1, 2005 NU Form 10-K, File No. 1-5324)

10.30.2 Amendment No. 2 to Northeast Utilities Deferred Compensation Plans for Executives, effective September 12, 2006 (Exhibit 10.33.2, 2006 NU Form 10-K, File No. 1-5324)

10.30.3 Amendment No. 3 to Northeast Utilities Deferred Compensation Plans for Executives, effective January 1, 2006 (Exhibit 10.33.3, 2006 NU Form 10-K, File No. 1-5324)

10.31 Northeast Utilities System's Second Amended and Restated Tax Allocation Agreement dated as of September 21, 2005 (Exhibit D.4 to Amendment No. 1 to U5S Annual Report for the year ended December 31, 2004, filed September 30, 2005, File No. 1-5324)

(C) NU and CL&P

10.1 CL&P Transition Property Purchase and Sale Agreement between CL&P Funding LLC and CL&P, dated as of March 30, 2001 (Exhibit 10.55, 2001 CL&P Form 10-K, File No. 0-11419)

10.2 CL&P Transition Property Servicing Agreement CL&P Funding LLC and CL&P, dated as of March 30, 2001 (Exhibit 10.56, 2001 CL&P Form 10-K, File No. 0-11419)

(D) NU and PSNH

10.1 PSNH Purchase and Sale Agreement with PSNH Funding LLC dated as of April 25, 2001 (Exhibit 10.57, 2001 PSNH Form 10-K, File No. 1-6392)

10.2 PSNH Servicing Agreement with PSNH Funding LLC dated as of April 25, 2001 (Exhibit 10.58, 2001 PSNH Form 10-K, File No. 1-6392)

10.3 PSNH Purchase and Sale Agreement with PSNH Funding LLC2 dated as of January 30, 2002 (Exhibit 10.59 2001 PSNH Form 10-K, File No. 1-6392)

10.4 PSNH Servicing Agreement with PSNH Funding LLC2 dated as of January 30, 2002 (Exhibit 10.60, 2001 PSNH Form 10-K, File No. 1-6392)

(E) NU and WMECO

10.1 Lease and Agreement, dated as of December 15, 1988, by and between WMECO and Bank of New England, N.A., with BNE Realty Leasing Corporation of North Carolina (Exhibit 10.63, 1988 WMECO Form 10-K, File No. 0-7624)

10.2 WMECO Transition Property Purchase and Sale Agreement between WMECO Funding LLC and WMECO, dated as of May 17, 2001 (Exhibit 10.61, 2001 WMECO Form 10-K, File No. 0-7624)

10.3 WMECO Transition Property Servicing Agreement between WMECO Funding LLC and WMECO, dated as of May 17, 2001 (Exhibit 10.62, 2001 WMECO Form 10-K, File No. 0-7624)

*12 Ratio of Earnings to Fixed Charges

*13 Annual Report to Security Holders (Each of the Annual Reports is filed only with the Form 10-K of that respective registrant)

*13.1 Annual Report of CL&P

*13.2 Annual Report of WMECO

*13.3 Annual Report of PSNH

*21 Subsidiaries of the Registrant

*23 Consent of Independent Registered Public Accounting Firm

*31 Rule 13-a - 14(a)/15 d - 14(a) Certifications

(A) Northeast Utilities

31 Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of NU required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

31.1 Certification of David R. McHale, Senior Vice President and Chief Financial Officer of NU required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

(B) The Connecticut Light and Power Company

31 Certification of Leon J. Olivier, Chief Executive Officer of CL&P required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

31.1 Certification of David R. McHale, Senior Vice President and Chief Financial Officer of CL&P required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

(C) Public Service Company of New Hampshire

31 Certification of Leon J. Olivier, Chief Executive Officer of PSNH required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

31.1 Certification of David R. McHale, Senior Vice President and Chief Financial Officer of PSNH required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

(D) Western Massachusetts Electric Company

31 Certification of Leon J. Olivier, Chief Executive Officer of WMECO required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

31.1 Certification of David R. McHale, Senior Vice President and Chief Financial Officer of WMECO required by Rule 13a - 14(a)/15d - 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

*32 Section 1350 Certificates

(A) Northeast Utilities

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities, and David R. McHale, Senior Vice President and Chief Financial Officer of Northeast Utilities, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

(B) The Connecticut Light and Power Company

Certification of Leon J. Olivier, Chief Executive Officer of CL&P, and David R. McHale, Senior Vice President and Chief Financial Officer of CL&P, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

(C) Public Service Company of New Hampshire

Certification of Leon J. Olivier, Chief Executive Officer of PSNH, and David R. McHale, Senior Vice President and Chief Financial Officer of PSNH, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

(D) Western Massachusetts Electric Company

Certification of Leon J. Olivier, Chief Executive Officer of WMECO, and David R. McHale, Senior Vice President and Chief Financial Officer of WMECO, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 28, 2008

Exhibit 10.3

SUMMARY OF TRUSTEE COMPENSATION ARRANGEMENT

Northeast Utilities ("NU") pays an annual retainer to each Trustee who is not employed by NU or its subsidiaries. NU pays an additional retainer to the Lead Trustee and the Chairs of each of the Audit, Compensation, Corporate Responsibility, Corporate Governance and Finance Committees. Each retainer is paid in four equal quarterly installments. NU pays one-half of the value of the retainers payable to the Chairs of each of the Audit and Compensation Committees in the form of NU common shares. The following table sets forth the amounts of non-employee Trustee retainers for 2008:

Retainer	Annual Amount
Annual Retainer (all Trustees)	$45,000
Lead Trustee	$50,000
Audit Committee Chair	$20,000
Compensation Committee Chair	$15,000
Corporate Responsibility Committee Chair	$7,500
Corporate Governance Committee Chair	$7,500
Finance Committee Chair	$10,000

During 2008, NU will pay each non-employee Trustee $1,500 for attendance in person or by telephone at each meeting of the full Board and each committee on which the Trustee serves.

Under the Northeast Utilities Incentive Plan, each non-employee Trustee is eligible to receive share-based grants during each calendar year. In January 2008, each non-employee Trustee was granted 3,000 Restricted Share Units ("RSUs") under the Incentive Plan, all of which will vest and be distributed in equivalent NU common shares on January 10, 2009.

Before 2007, NU distributed common shares in respect of only one-half of RSUs granted to non-employee Trustees upon vesting. NU deferred the distribution of common shares with respect to the remaining one-half of the RSUs until four years after the vesting date, or if a Trustee terminates service on the Board for any reason before this distribution date, the month following the month in which a Trustee ceases to serve on the Board. In 2007, the Board adopted share ownership guidelines applicable to the non-employee Trustees and eliminated the distribution deferral provision for RSUs. However, Trustees were entitled to elect, on or before December 31, 2007, to make a new irrevocable election to continue the four-year deferral, by grant year. The share ownership guidelines require Trustees to attain ownership of 7,500 common shares and/or RSUs, which have a fair market value equal to approximately five times the va lue of the current annual retainer, by 2012.

Prior to the beginning of each calendar year, non-employee Trustees may irrevocably elect to receive all or any portion of their retainers and fees in the form of common shares. Pursuant to the Northeast Utilities Deferred Compensation Plan for Trustees, each Trustee may also irrevocably elect to defer receipt of all or a portion of cash and/or equity compensation, including RSUs issued under the Incentive Plan. Deferred funds are credited with interest at the rate set forth in Section 37-1 of the Connecticut General Statutes, which rate is currently 8.0%. Deferred compensation is payable either in a lump sum or in one to five annual installments in accordance with the Trustee's prior election.

A non-employee Trustee who performs additional Board-related services in the interest of NU or any of its subsidiaries upon the request of either the Board or the Chairman of the Board is entitled to receive additional compensation equal to $750 per half-day plus reasonable expenses. In addition, NU pays travel-related expenses for spouses of Trustees who attend Board functions. The Internal Revenue Service considers payment of travel expenses for a Trustee's spouse to be imputed income to the individual Trustee. As a result, NU provides each Trustee with a gross-up payment in an amount sufficient to pay the income tax liability for the imputed income attributable to such travel expenses.

Exhibit 10.1.2

AMENDMENT AND RENEWAL OF SERVICE CONTRACT
NORTHEAST UTILITIES SERVICE COMPANY AND
[NAME OF COMPANY]

This Amendment and Renewal of Service Contract ("Agreement") is made and entered into as of the 31st of December 2007, by and between Northeast Utilities Service Company ("Service Company") and [name of company] ("Associate Company").

WHEREAS, under the terms of the Service Contract by and between Service Company and Associate Company, Service Company is willing to render certain services to Associate Company at cost, determined in accordance with the applicable rules and regulations promulgated by the Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act of 1935 (the "35 Act"); and

WHEREAS, the 35 Act was repealed in 2006, and jurisdiction over certain of Service Company's activities was transferred from the SEC to the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act, as amended (the "Act"), including the provision of services for affiliated companies at cost; and

WHEREAS, the Service Contract between Service Company and Associate Company expires as of December 31, 2007; and

WHEREAS, both parties deem it to be in the their best interests to renew the Service Contract for an additional period of one year on the same terms and conditions and in accordance with the requirements of FERC.

NOW, THEREFORE, in consideration of the premises and mutual agreements herein contained, it is agreed as follows:

1. Amendment of Service Contract. The Service Contract between Service Company and Associate Company is hereby amended as follows:

   (a) All references to the "Act" in the Service Contract and attachments shall be deemed to refer to the Federal Power Act.

   (b) The reference to the "SEC" in Section 4 of the Service Contract shall be deleted and replaced with "FERC."

   (c) The phrase "Rule 91 of the SEC" contained in Section 3 of the Service Contract and on Appendix A shall be replaced with the phrase "applicable rules and requirements of FERC."

2. Renewal of Service Contract. (a) The Service Contract between Service Company and Associate Company, as heretofore amended, is hereby renewed as of January 1, 2008, for a period of one year.

(b) Except as modified and amended by this Agreement, all terms and conditions of the Service Contract shall continue in full force and effect during such renewal period.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed by their respective officers thereunto duly authorized, all as of the date first above written.

NORTHEAST UTILITIES SERVICE COMPANY

Attest: By:_____
Name:
Title:

_____
Assistant Secretary

[NAME OF COMPANY]

Attest: By: _____
Name:
Title:

_____
Assistant Secretary

Exhibit 10.20.2

General Release and Covenant Not to Sue

You Are Advised to Consult with an Attorney
Before You Sign This Release

I, Cheryl W. Grise, in consideration for the Special Benefits described in paragraph 1, below, which benefits I agree I would not otherwise be entitled to receive, agree to release and forever discharge Northeast Utilities, Northeast Utilities Service Company, NU Enterprises, Inc., Select Energy, Inc., Select Energy Services, Inc., Select Energy Contracting, Inc., Select Energy New York, Inc., Mode 1 Communications, Inc., NU Enterprises, Inc., Northeast Generation Company, Northeast Generation Services Company, Holyoke Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, Yankee Energy System, Inc., and their past, present and future parent corporations, subsidiaries, divisions, subdivisions, affiliates and related companies or their predecessors, successors and assigns and all past and present a nd future directors, officers and employees of these entities personally, or as directors, officers and employees (collectively, "the Company"), from any and all claims, demands, charges, grievances, actions, or liabilities of any nature whatsoever, known or unknown, suspected or unsuspected, arising from or relating in any way to any act or omission occurring prior to the date of this General Release and Covenant Not to Sue ("Release"), directly or indirectly relating to my employment with the Company or the termination of my employment with the Company pursuant to my planned retirement on June 30, 2007.

I agree that I have executed this Release on my own behalf, and also on behalf of my heirs, agents, representatives, successors and assigns that I now have or may have in the future. By signing this Release, I hereby waive, release and forever discharge the Company from any and all claims under federal, state and local law, including but not limited to claims of employment discrimination or retaliation arising under the Age Discrimination in Employment Act of 1967, *as amended*, Title VII of the Civil Rights Act of 1964, *as amended*, *42* U.S.C. sections 1981 and 1983, the Employee Retirement Income Security Act of 1974, the Rehabilitation Act of 1973, the Americans with Disabilities Act, the Family and Medical Leave Act, and the Occupational Safety and Health Act.

I also agree that by signing this Release, I hereby waive, release, and forever discharge any and all statutory or common law claims and claims under any tort or contract theory, including but not limited to, claims for personal injuries, emotional distress, breach of express or implied contract, wrongful discharge, or violation of public policy.

I agree that I will not institute a claim, grievance, charge, lawsuit, or action of any kind against the Company, including but not limited to claims related to my employment with the Company or the termination of my employment with the Company pursuant to my planned retirement on or before June 30, 2007. I also agree that if I bring any form of legal action against the Company, which does not include the reporting or otherwise communicating of any nuclear safety concern, workplace safety concern, public safety concern, or claim of discrimination or retaliation to the U. S. Nuclear Regulatory Commission, the U. S. Department of Labor, the Equal Employment Opportunity Commission, or any federal or state government agency, I must forfeit all amounts paid to me pursuant to this Release and the Company will be relieved of any further obligations owed under this Release. I further agree that if I violate this Release by instituting a legal action against the Company, I agree that I will pay all costs and expenses of defending against the lawsuit incurred by the Company, including reasonable attorneys' fees.

I understand that nothing in this Agreement shall interfere with my right to file a charge, cooperate or participate in an investigation or proceeding conducted by the Equal Employment Opportunity Commission or other federal or state regulatory or law enforcement agency. However, the consideration provided to me in this Agreement shall be the sole relief provided for the claims that are released by me herein and I understand that I will not be entitled to recover and agree to waive any monetary benefits or recovery against the Company in connection with any such claim, charge or proceeding without regard to who has brought such complaint or charge.

I further acknowledge and agree that:

1. The Special Benefits consist of a Special Pension Benefit and a Special Payment. The Special Pension Benefit is in addition to the amount payable to me under the Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Companies (the "SERP"). The Special Pension Benefit, when added to my annual SERP Make-Whole Benefit and my Northeast Utilities Service Company Retirement Plan benefit, will provide an annual benefit of $644,000 (or the actuarially equivalent benefit if a benefit payment option other than the form that pays 50% to my surviving spouse is selected), payable monthly commencing July 1, 2007 in a form that provides to my surviving spouse, on a monthly basis for his lifetime commencing on the first day of the month immediately following my death, the contingent annuitant payment corresponding to the benefit payment option that I select. Th e Special Pension Benefit will be provided in the same actuarially equivalent form chosen by me for the SERP. Amounts are expressed before applicable tax withholdings. Notwithstanding the foregoing, the commencement of payment of the Special Pension Benefit and my Make-Whole Benefit under the SERP shall be delayed until January 1, 2008 in accordance with Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), in recognition that I am a "specified employee" under the terms of Section 409A, effective for the 12-month period beginning April 1, 2007. On January 1, 2008, the amounts otherwise payable from July 1, 2007 through December 31, 2007 shall be paid to me in a lump sum together with interest on such delayed payments calculated at the rate of 5.9% per year. Except as otherwise specifically provided in this Agreement, the terms of the SERP shall govern my Special Pension Benefit, including without limitation the terms thereof concerning complia nce with Section 409A of the Code. The Special Payment is a single lump sum payment of $120,535, less all applicable withholdings, that will be paid as soon as practicable after January 1, 2008, but not later than January 15, 2008. The award for the 2007 Annual Incentive Program will be paid to me at target, which shall be 65% of the salary that was paid to me in the first six months of 2007; the award will be paid at the same time other Program participants are paid, but not later than March 15, 2008. If performance against Program goals does not support a target payout, then a special payment outside the Program will be paid to meet this obligation. I understand and agree that no other payments or benefits for which I might otherwise be eligible pursuant to a voluntary retirement on June 30, 2007 shall be reduced because of this agreement. The Special Pension Benefit and Special Payment constitute valid and sufficient consideration for this Release, in that these are benefits to which I would not have been entitled had I not signed this Release, and are reflected along with my other payments and benefits in the spreadsheet attached as Appendix A.

2. The Company has advised me to consult with an attorney and a financial advisor prior to signing this Release and I further acknowledge that I have been given a full and fair opportunity to do so. I acknowledge also that I have reviewed, carefully considered, and fully understand the terms, nature and effect of this Release and that this release is made in full contemplation of my planned retirement from the Company on or before June 30, 2007.

3. I have been given a period of twenty-one (21) days to consider and review this Release. I understand that I have seven (7) days after executing the Release within which to revoke my acceptance of the Release by notifying Gregory B. Butler, Senior Vice President and General Counsel in writing of my intentions to revoke. I further understand that this Release is not effective or enforceable until the revocation period expires without a revocation by me.

4. This Release does not waive any claims that I may have which arise after the date this Release becomes effective.

5. During the course of my employment with the Company, I have learned about, had access to, or used confidential and proprietary information about the Company, including, for example, financial information about the Company, the names of the Company's actual or prospective suppliers and/or customers, marketing or financial studies, marketing or financial strategies, or any other business plans or strategies of the Company that are not in the public forum. I acknowledge that such confidential and proprietary information is the property of the Company and I expressly agree not to disclose, divulge or communicate such confidential and proprietary information without the Company's prior, express written consent.

6. 1 have not relied on any representations, promises, or agreements of any kind made to me in connection with any decision to accept the Release except for those set forth herein.

7. I further agree that I will keep confidential the terms, amount and the facts of the agreements set forth in this Release and I agree that I will not disclose any information concerning this Release, and its terms and conditions, including the amount of monies paid to me, to anyone other than my attorney, accountant, tax advisor, immediate family, or the state Unemployment Compensation Commission. I understand that nothing in this Release prohibits me from disclosing any of the above information where required by law.

8. I understand that if any part of this Release is determined to be invalid, illegal or otherwise unenforceable, the remaining provisions of this Release shall not be affected and will remain in full force and effect.

9. This Release, consisting of five (5) pages, and Addendum A set forth the entire agreement between me and the Company regarding the issues herein addressed, and supersedes any prior or 'contemporaneous oral or written agreement or understanding, between the Company and me with respect to said issues, and cannot be changed except in a writing signed by all parties. Notwithstanding the above, I understand that this release does not alter or affect in any way any obligations that I or the Company may have pursuant to my Employment Agreement. Any obligations between and among the Company and me pursuant to said Employment Agreement exist separate and apart from this instant Release.

By: /s/ Cheryl W. Grise
Name: Cheryl W. Grise

Subscribed and sworn to before me
on this the 22nd day of June, 2007
By: /s/ Duncan R. MacKay
Name: Duncan R. MacKay

Exhibit 10.26

Northeast Utilities Incentive Plan

Amended and Restated by Northeast Utilities Compensation Committee of the Board of Trustees on February 13, 2007

Approved by the Shareholders on May 8, 2007.

ARTICLE I
PURPOSE

The purpose of the Northeast Utilities Incentive Plan (the "Plan") is to provide (i) designated employees of the Company (as hereinafter defined in Article X) and (ii) non-employee members of the Board of Trustees (the "Board") of Northeast Utilities, a Massachusetts business trust ("NU"), with the opportunity to receive annual incentive compensation and grants of incentive stock options, nonqualified stock options, stock appreciation rights, restricted shares, restricted share units and performance units. The Company believes that the Plan will assist it in recruiting talented employees who will contribute materially to the growth of the Company, thereby benefiting NU's shareholders and aligning the economic interests of the participants with those of the shareholders.

For purposes of the Plan, definitions appear in the Plan and as set forth in Article XIV.

ARTICLE II
ADMINISTRATION

1. Committee. The Plan shall be administered and interpreted by the Board's Compensation Committee, or the person or persons to which such committee delegates any of its functions under the Plan (the "Committee"). The Committee may consist of two or more persons appointed by the Board, all of whom shall be "outside directors" as defined under section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code") and related Treasury regulations and "non-employee directors" as defined under Rule 16b-3 under the Exchange Act. Members of the Committee shall be "independent' as defined under the listing standards of the New York Stock Exchange. However, the Board may ratify or approve any grants as it deems appropriate or as are submitted by the Committee.

2. Committee Authority. The Committee shall have the authority to amend or terminate the Plan as provided in Article XII. The Committee shall have the sole authority to (i) establish, and review the Company's and the Grantee's, as defined below, performance against annual goals for purpose of the annual incentives to be distributed and determine the individuals to whom grants shall be made under the Plan, (ii) determine the type, size and terms of the grants to be made to each such individual, (iii) determine the time when the grants will be made and the duration of any applicable exercise or restriction period, including the criteria for exercisability and the acceleration of exercisability (iv) establish such rules and regulations or take such action as it deems necessary or advisable for the proper administration of the Plan, including the delegation of day-to-day plan administration, and (v) deal with any other matters arising under the Plan.

3. Committee Determinations. The Committee shall have full power and authority to administer and interpret the Plan, to make factual determinations and to adopt or amend such rules, regulations, agreements and instruments for implementing the Plan and for the conduct of its business as it deems necessary or advisable, in its sole discretion. The Committee's interpretations of the Plan and all determinations made by the Committee pursuant to the powers vested in it hereunder shall be conclusive and binding on all persons having any interest in the Plan or in any awards granted hereunder including, but not limited to, the Company, the Committee, the Board, the affected Participants, and their respective successors in interest. All powers of the Committee shall be executed in its sole discretion, in the best interest of the Company, not as a fiduciary, and in keeping wi th the objectives of the Plan and need not be uniform as to similarly situated individuals.

ARTICLE III
ANNUAL INCENTIVE AWARDS

1. Eligibility for Participation. Each employee of the Company classified as a Vice President or higher (an "Executive Employee") shall be eligible to receive an annual incentive award (an "Award") under the Plan

2. Annual Awards.

(a) As soon as practicable after the start of each fiscal year of NU, but in any event within 90 days, the Committee shall set the Performance Goals for the Company which shall be the basis for determining the Awards to be paid to each Executive Employee for such fiscal year and the Committee shall communicate the target and the percentages (including minimums and maximums) for each Executive Employee applicable to each level of achievement against the target set. In no event may an individual Award for an Executive Employee exceed $4,000,000.

(b) The maximum amount of an Award for an Executive Employee shall be based upon the Company's performance compared against the Performance Goals set for that fiscal year. The actual amount of the Award for any Executive Employee shall be reduced, accordingly, by the Committee if the Executive Employee does not satisfy one or more individual financial or nonfinancial objectives set by the Committee for that Executive Employee as of the beginning of the relevant fiscal year. Any such objectives for an Executive Employee shall be set by the Committee and announced to the affected Executive Employee no later than 90 days after the commencement of the relevant fiscal year of NU.

(c) The Committee shall certify and announce the Awards that will be paid by the Company to each Executive Employee as soon as practicable following the final determination of the Company's financial results for the relevant fiscal year. Payment shall normally be made in cash, or in shares of Company Stock or Options, the value of which shall equal the amount to be distributed, all as determined by the Committee, within 90 days following the end of such fiscal year, provided that the Executive Employee has not separated from employment by the Company prior to the date that payment is due except as otherwise specifically provided in a contract between the Company and the Executive Employee. The Committee may provide for complete or partial exceptions to this requirement if an Executive Employee's employment terminated on account of Retirement, termination without Cause, death or Disability or a Chan ge of Control.

ARTICLE IV
STOCK-BASED GRANTS

1. Grants. Grants under the Plan may consist of grants of incentive stock options ("Incentive Stock Options") or nonqualified stock options ("Nonqualified Stock Options") (Incentive Stock Options and Nonqualified Stock Options are collectively referred to as "Options"), restricted stock ("Restricted Stock"), restricted share units ("Restricted Share Units" or "RSUs"), stock appreciation rights ("SARs"), and/or performance units ("Performance Units") (hereinafter collectively referred to as "Grants"). Grants may be awarded singly, in combination or in tandem with other Grants. All Grants shall be subject to the terms and conditions set forth herein and to such other terms and conditions consistent with this Plan as the Committee deems appropriate and as are specified in writing by the Committee to the individual in a grant inst rument or an amendment to the grant instrument (the "Grant Instrument"). The Committee shall approve the form and provisions of each Grant Instrument. Grants under a particular Section of the Plan need not be uniform as among the Grantees, as defined below.

2. Eligibility for Participation.

(a) Eligible Persons. All employees of the Company ("Employees"), including Employees who are officers or members of the Board, contractors of the Company ("Contractors"), and members of the Board who are not Employees ("Non-Employee Trustees") shall be eligible to receive Grants under the Plan. Contractors shall be eligible to receive Grants only of Nonqualified Stock Options.

(b) Selection of Grantees. The Committee shall select the Employees and Contractors to receive Grants and shall determine the number of shares of Company Stock subject to a particular Grant in such manner as the Committee determines. Employees, Contractors and Non-Employee Trustees who receive Grants under this Plan shall hereinafter be referred to as "Grantees".

(c) Collective Bargaining Employees. Anything to the contrary in this Plan notwithstanding, no Employee whose terms and conditions of employment are subject to negotiation with a collective bargaining agent shall be eligible to receive Grants under this Plan until the agreement between the Company and such collective bargaining agent with respect to the Employee provides for participation in the Plan.

3. Granting of Options.

(a) Number of Shares. The Committee shall determine the number of shares of Company Stock that will be subject to each Grant of Options to Employees and Contractors subject to the overall limits of Article IX.

(b) Type of Option and Price.

(i) The Committee may grant Incentive Stock Options that are intended to qualify as "incentive stock options" within the meaning of section 422 of the Code or Nonqualified Stock Options that are not intended so to qualify or any combination of Incentive Stock Options and Nonqualified Stock Options, all in accordance with the terms and conditions set forth herein. Incentive Stock Options may be granted only to Employees. Nonqualified

Stock Options may be granted to Employees, Contractors and Non-Employee Trustees.

(ii) The purchase price (the "Exercise Price") of Company Stock subject to an Option shall be determined by the Committee and shall be equal to or greater than the Fair Market Value (as defined below) of a share of Company Stock on the date the Option is granted; provided, however, that an Incentive Stock Option may not be granted to an Employee who, at the time of grant, owns stock possessing more than 10 percent of the total combined voting power of all classes of stock of the Company or any parent or subsidiary of the Company, unless the Exercise Price per share is not less than 110% of the Fair Market Value of Company Stock on the date of grant. The Committee may not modify the applicable Exercise Price after the date of Grant.

(iii) If the Company Stock is publicly traded, then the Fair Market Value per share shall be the closing price of the Company Stock as reported in the Wall Street Journal as composite transactions for the relevant date (or the latest date for which such price was reported if such date is not a business day), or if not available, determined as follows: (x) if the principal trading market for the Company Stock is the New York Stock Exchange, the last reported sale price thereof on the relevant date or (if there were no trades on that date) the latest preceding date upon which a sale was reported, (y) if the principal trading market for the Company Stock is a national securities exchange other than the New York Stock Exchange or is the NASDAQ National Market, the last reported sale price thereof on the relevant date or (if there were no trades on that date) the latest preceding date upon which a sale w as reported, or (z) if the Company Stock is not principally traded on such exchange or market, the mean between the last reported "bid" and "asked" prices of Company Stock on the relevant date, as reported on NASDAQ or, if not so reported, as reported by the National Daily Quotation Bureau, Inc. or as reported in a customary financial reporting service, as applicable and as the Committee determines. If the Company Stock is not publicly traded or, if publicly traded, is not subject to reported transactions or "bid" or "asked" quotations as set forth above, the Fair Market Value per share shall be as determined by the Committee.

(c) Option Term. The Committee shall determine the term of each Option. The term of any Option shall not exceed ten years from.the date of grant. However, an Incentive Stock Option that is granted to an Employee who, at the time of grant, owns stock possessing more than 10 percent of the total combined voting power of all classes of stock of the Company, or any parent or subsidiary of the Company, may not have a term that exceeds five years from the date of grant.

(d) Exercisability of Options. Options shall become exercisable in accordance with such terms and conditions, consistent with the Plan, as may be determined by the Committee and specified in the Grant Instrument. The Committee may accelerate the exercisability of any or all outstanding Options at any time for any reason.

(e) Termination of Employment, Retirement, Disability or Death.

(i) Except as provided below, an Option may be exercised only while the Grantee is employed by, or providing service to, the Company as an Employee, a Contractor, or a member of the Board. In the event that a Grantee ceases to be employed by, or provide service to, the Company then, unless the Committee deems otherwise, all outstanding Options will expire upon termination from employment or service with the Board for

Cause, or any other reason, including termination on account of "Retirement," "Disability," or death.

(ii) For purposes of this Plan and programs thereunder:

(A) "Cause" shall mean, except to the extent specified otherwise by the Committee acting on behalf of the Company, (i) the Grantee's conviction of a felony, (ii) in the reasonable determination of the Committee, the Grantee's (x) commission of an act of fraud, embezzlement, or theft in connection with the Grantee's duties in the course of the Grantee's employment with the Company, (y) acts or omissions causing intentional, wrongful damage to the property of the Company or intentional and wrongful disclosure of confidential information of the Company, or (z) engaging in gross misconduct or gross negligence in the course of the Grantee's employment with the Company, or (iii) the Grantee's material breach of his or her obligations under any written agreement with the Company if such breach shall not have been remedied within 30 days after receiving written notice from the Committee specifying the details thereof. For purposes of this Program, an act or omission on the part of a Grantee shall be deemed "intentional" only if it was not due primarily to an error in judgment or negligence and was done by Grantee not in good faith and without reasonable belief that the act or omission was in the best interest of the Company. In the event a Grantee's employment or service is terminated for cause, in addition to the immediate termination of all Grants, the Grantee shall automatically forfeit all shares underlying any exercised portion of an Option for which the Company has not yet delivered the share certificates, upon refund by the Company of the Exercise Price paid by the Grantee for such shares.

(B) "Disability" shall mean a Grantee's being determined to be disabled within the meaning of the long-term disability plan or program that is a part of the Northeast Utilities Service Company Group Insurance Plan (or any successor plan or program, hereafter, the "LTD Program"); provided, however, that any payment to a Participant on account of a Disability may not commence until the Participant is determined to be disabled pursuant to Section 409A(a)(2)(C) of the Code, or as renumbered.

(C) "Employed by, or provide service to, the Company" shall mean employment or service as an Employee, Contractor or member of the Board (so that, for purposes of exercising Options and SARs and satisfying conditions with respect to Restricted Stock, RSUs and Performance Units, a Grantee shall not be considered to have terminated employment or service until the Grantee ceases to be an Employee, Contractor and member of the Board), unless the Committee determines otherwise.

(D) "Retired" shall mean a termination of employment from the Company, other than for "Cause" on or after the earlier to occur of (x) attainment of age 65, (y) eligibility for payments under the Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Companies, or employment-related agreement with the Company, or (z) attainment of age 55 after completing at least ten years of vesting service under the Northeast Utilities Service Company 401 k Plan.

(f) Exercise of Options. A Grantee may exercise an Option that has become exercisable, in whole or in part, by delivering a notice of exercise to the Company with payment of the Exercise Price. The Grantee shall pay the Exercise Price for an Option as specified by the Committee:

(i) in cash,

(ii) with the approval of the Committee, by delivering shares of Company Stock owned by the Grantee (including Company Stock acquired in connection with the exercise of an Option or Restricted Stock, as defined below, granted under this Plan, subject to such restrictions as the Committee deems appropriate including placing the same restrictions on the shares of Company Stock obtained through the exchange of the Restricted Stock) and having a Fair Market Value on the date of exercise equal to the Exercise Price, or

(iii) by such other method as the Committee may approve, including payment through a broker in accordance with procedures permitted by Regulation T of the Federal Reserve Board. The Grantee shall pay the Exercise Price and the amount of any withholding tax due at the time of exercise.

(g) Limits on Incentive Stock Options. Each Incentive Stock Option shall provide that, if the aggregate Fair Market Value of the stock on the date of the grant with respect to which Incentive Stock Options are exercisable for the first time by a Grantee during any calendar year, under the Plan or any other stock option plan of the Company exceeds $100,000, then the option, as to the excess, shall be treated as a Nonqualified Stock Option. An Incentive Stock Option shall not be granted to any person who is not an Employee of the Company.

ARTICLE V
STOCK-BASED GRANTS TO NON-EMPLOYEE TRUSTEES

1. Eligibility for Participation. Non-Employee Trustees shall be eligible to receive Grants as set forth in Article IV; provided, that the number of shares of Company Stock subject to each Grant of Options, as well as the terms of all Grants, to Non-Employee Trustees shall be approved by the Board, in accordance with Article (9) of the Declaration of Trust of Northeast Utilities, as amended.

2. Terms of Retirement. The words "age 65" in the definition of "Retired" in Section 3(e)(ii)(D) of Article IV shall be read as "age 70" with respect to Non-Employee Trustees.

ARTICLE VI
RESTRICTED STOCK AND RESTRICTED SHARE UNIT GRANTS

1. Restricted Stock Grants. Subject to the terms and conditions of the Plan, the Committee may issue or transfer shares of Company Stock to a Grantee with such restrictions as the Committee deems appropriate ("Restricted Stock"). The following provisions are applicable to Restricted Stock:

(a) General Requirements. Shares of Company Stock issued or transferred pursuant to Restricted Stock Grants may be issued or transferred in exchange for services performed or to be performed. The Committee may establish conditions under which restrictions on shares of Restricted Stock shall lapse over a period of time or according to such other criteria as the Committee deems appropriate. The period of time during which the Restricted Stock will remain subject to restrictions (the "Restriction Period") will be designated in the Grant Instrument

(b) Number of Shares. The Committee shall determine the number of shares of Company Stock to be issued or transferred pursuant to a Restricted Stock Grant and the restrictions applicable to such shares, subject to the limitations contained in Article IX.

(c) Requirement of Employment or Service. If the Grantee ceases to be employed by, or provide service to, the Company during the Restriction Period, or if other specified conditions are not met, the Restricted Stock Grant shall terminate as to all shares covered by the Grant as to which the restrictions have not lapsed, and those shares of Company Stock must be immediately returned to the Company. The Committee may, however, provide for complete or partial exceptions to this requirement as it deems appropriate.

(d) Restrictions on Transfer and Legend on Share Certificate. During the Restriction Period, a Grantee may not sell, assign, transfer, pledge or otherwise dispose of the shares of Restricted Stock except to a Successor Grantee, as defined below. The Committee may determine that the Company will issue certificates for shares of Restricted Stock, in which case each certificate for a share of Restricted Stock shall contain a legend giving appropriate notice of the restrictions in the Grant. The Grantee shall be entitled to have the legend removed from the share certificate covering the shares subject to restrictions when all restrictions on such shares have lapsed. The Committee may determine that the Company will not issue certificates for shares of Restricted Stock until all restrictions on such shares have lapsed, or that the Company will retain possession of certifica tes for shares of Restricted Stock until all restrictions on such shares have lapsed.

(e) Right to Vote and to Receive Dividends. Unless the Committee determines otherwise, the Grantee shall have the right to vote Restricted Stock and to receive any dividends or other distributions paid on such shares during the Restriction Period subject to any restrictions deemed appropriate by the Committee.

(f) Lapse of Restrictions. All restrictions imposed on Restricted Stock shall lapse upon the expiration of the applicable Restriction Period and the satisfaction of all conditions imposed by the Committee. The Committee may determine, as to any or all Restricted Stock Grants, that the restrictions shall lapse without regard to any Restriction Period.

2. Restricted Share Unit Grants.

(a) Restriction Period. The Committee may make Grants of Restricted Share Units to Employees and Non-Employee Trustees representing the right to receive shares of Company Stock, cash, or both, as determined by the Committee (hereafter, "Restricted Share Units"). At the end of the Restriction Period, subject to any deferral election that may be made or applied to the Grant pursuant to subsection (c) below, cash or shares or both shall be delivered to the Grantee (unless previously forfeited). Restricted Share Units may not be sold, assigned, transferred, pledged or otherwise encumbered during the Restriction Period. A Grantee of Restricted Share Units shall have none of the rights of a holder of Company Stock unless and until shares of Company Stock are actually delivered in satisfaction of such Restricted Share Units.

(b) Number of Units. The Committee shall determine the number of Restricted Share Units pursuant to a Restricted Share Unit Grant and the restrictions applicable to such shares, subject to the limitations contained in Article IX.

(c) Requirement of Employment or Service. If the Grantee ceases to be employed by, or provide service to, the Company during a period designated in the Grant Instrument as the Restriction Period, or if other specified conditions are not met, the Restricted Share Unit Grant shall terminate as to all Restricted Share Units covered by the Grant as to which the

restrictions have not lapsed. The Committee may, however, provide for complete or partial exceptions to this requirement if an Executive Employee's employment or Non-Employee Trustee's service with the Board ends on account of Retirement, termination without Cause, death or Disability or due to a Change of Control, as it deems appropriate.

(d) Dividend Equivalents. The Committee may determine that a Grant Instrument with respect to Restricted Share Units may provide that the Grantee shall be entitled to receive as compensation from the Company dividend equivalents with respect thereto, in the form determined by the Committee from the effective date of the Grant Instrument through the earlier of (i) the date the Restricted Share Unit is forfeited, and (ii) the date Company Stock representing such Restricted Share Units or cash is delivered to the Grantee as provided herein.

(e) Deferrals of Restricted Share Units. The Committee may provide for the automatic deferral of the payment of Restricted Share Units upon the lapse of restrictions on the Grant or permit a Grantee to elect deferral by filing a written election with the Committee in accordance with such procedures as the Committee may from time to time specify. Such deferral will extend until the date or dates specified in such election; provided, however, that any such deferral election shall be made in accordance with rules under Section 409A of the Code.

3. Withholding. The Company shall have the right to deduct from any settlement of a Grant of Restricted Shares or Restricted Share Units, including the delivery or vesting of shares or dividend equivalents, an amount sufficient to cover withholding required by law for any federal, state or local taxes or to take such other action as may be necessary to satisfy any withholding obligations. The Committee may permit shares to be used to satisfy required tax withholding, and such shares shall be valued at the fair market value as of the settlement date of the applicable Grant.

4. Section 162(m). Notwithstanding any other provision of the Plan or the terms of any Grant or Award issued hereunder, Grants of Restricted Stock or Restricted Share Units under this Article VI are not intended to be or meet the requirements for "qualified performance based compensation" under Section 162(m) of the Code or Treasury Regulation § 1.162-27(e).

ARTICLE VII
STOCK APPRECIATION RIGHTS

1. Stock Appreciation Rights.

(a) General Requirements. The Committee may grant stock appreciation rights ("SARs") to a Grantee separately or in tandem with any Option (for all or a portion of the applicable Option). Tandem SARs may be granted either at the time the Option is granted or at any time thereafter while the Option remains outstanding; provided, however, that, in the case of an Incentive Stock Option, SARs may be granted only at the time of the Grant of the Incentive Stock Option. The Committee shall establish the base amount of the SAR at the time the SAR is granted. The base amount of each SAR shall be equal to the per share Exercise Price of the related Option or, if there is no related Option, the Fair Market Value of a share of Company Stock as of the date of Grant of the SAR ("Base Amount"). The Committee may not modify the applicable Base Amount of the SAR after the date of Grant.

(b) Tandem SARs. In the case of tandem SARs, the number of SARs granted to a Grantee that shall be exercisable during a specified period shall not exceed the number of shares of Company Stock that the Grantee may purchase upon the exercise of the related Option during such period. Upon the exercise of an Option, the SARs relating to the Company Stock covered by such Option shall terminate. Upon the exercise of SARs, the related Option shall terminate to the extent of an equal number of shares of Company Stock.

(c) Exercisability. An SAR shall be exercisable during the period specified by the Committee in the Grant Instrument and shall be subject to such vesting and other restrictions as may be specified in the Grant Instrument. SARs may only be exercised while the Grantee is employed by the Company or during the applicable period after termination of employment as described in Article IV, Section 3(e). A tandem SAR shall be exercisable only during the period when the Option to which it is related is also exercisable.

(d) Value of SARs. When a Grantee exercises SARs, the Grantee shall receive in settlement of such SARs an amount equal to the "spread value" for the number of SARs exercised, payable in cash. The "spread value" for an SAR is the amount representing the difference by which the Fair Market Value of the underlying Company Stock on the date of exercise of the SAR exceeds the base amount of the SAR as described in Subsection (a).

(e) Form of Payment. For purposes of calculating the amount of cash to be received, shares of Company Stock shall be valued at their Fair Market Value on the date of exercise of the SAR and cash shall be distributed, net of applicable withholding taxes.

ARTICLE VIII
PERFORMANCE UNITS

1. Performance Units.

(a) General Requirements. The Committee may grant performance units ("Performance Units") to an Employee. Each Performance Unit shall represent the right of the Grantee to receive an amount based on the value of the Performance Unit, if performance goals established by the Committee are met. A Performance Unit shall be based on the Fair Market Value of a share of Company Stock or on such other measurement base as the Committee deems appropriate. The Committee shall determine the number of Performance Units to be granted and the requirements applicable to such Units, subject to the limitations contained in Article IX.

(b) Performance Period and Performance Goals. When Performance Units are granted, the Committee shall establish the Performance Period during which performance shall be measured, Performance Goals applicable to the Units and such other conditions of the Grant as the Committee deems appropriate. Performance Goals may relate to the financial performance of the Company or its operating units, the performance of Company Stock, individual performance, or such other criteria as the Committee deems appropriate.

(c) Payment with respect to Performance Units. At the end of each Performance Period, the Committee shall determine to what extent the Performance Goals and other conditions of the Performance Units are met and the amount, if any, to be paid with respect to the

Performance Units. Payments with respect to Performance Units shall be made in cash, in Company Stock, or in a combination of the two, as determined by the Committee.

(d) Requirement of Employment or Service. If the Grantee ceases to be employed by, or provide service to, the Company (as defined in Article IV, Section 3(e)) during a Performance Period, or if other conditions established by the Committee are not met, the Grantee's Performance Units shall be forfeited. The Committee may, however, provide for complete or partial exceptions to this requirement if an Executive Employee's employment ends on account of Retirement, termination without Cause, death or Disability or due to a Change of Control, as it deems appropriate.

(e) Designation as Qualified Performance-Based Compensation. The Committee may determine that Performance Units granted to a Grantee shall be considered "qualified performance-based compensation" under Section 162(m) of the Code. The provisions of this subsection (e) shall apply to Grants of Performance Units that are to be considered "qualified performance-based compensation" under Section 162(m) of the Code.

(i) Performance Goals. When Performance Units that are to be considered "qualified performance-based compensation" are Granted, the Committee shall establish in writing (i) the objective Performance Goals that must be met in order for amounts to be paid under the Performance Units, (ii) the Performance Period during which the performance goals must be met, (iii) the threshold, target and maximum amounts that may be paid if the Performance Goals are met, and (iv) any other conditions, including without limitation provisions relating to death, disability, other termination of employment or Change of Control, that the Committee deems appropriate and consistent with the Plan and Section 162(m) of the Code. The performance goals may relate to the Employee's business unit or the performance of the Company and its subsidiaries as a whole, or any combination of the foregoing.

(ii) Establishment of Goals. The Committee shall establish the Performance Goals in writing either before the beginning of the Performance Period or during a period ending no later than the earlier of (i) 90 days after the beginning of the Performance Period or (ii) the date on which 25% of the Performance Period has been completed, or such other date as may be required or permitted under applicable regulations under Section 162(m) of the Code. The performance goals shall satisfy the requirements for "qualified performance-based compensation," including the requirement that the achievement of the goals be substantially uncertain at the time they are established and that the goals be established in such a way that a third party with knowledge of the relevant facts could determine whether and to what extent the performance goals have been met. The Committee shall not have discretion to increase the amount of compensation that is payable upon achievement of the designated performance goals.

(iii) Maximum Payment. The number of Performance Units granted and paid in shares shall not exceed the limit specified under Article IX(1)(a). If Performance Units are paid in cash, the maximum amount that may be paid to an Employee with respect to a Performance Period is $4,000,000.

(iv) Announcement of Grants. The Committee shall certify and announce the results for each Performance Period to all Grantees immediately following the announcement of the Company's financial results for the Performance Period. If and to the extent that the Committee does not so certify that the performance goals have been met, the grants of Performance Units for the Performance Period shall be forfeited.

ARTICLE IX
AUTHORIZED SHARES

1. Shares Subject to the Plan.

(a) Shares Reserved for Grants and Awards. The aggregate number of common shares of NU, par value $5.00, ("Company Stock") that may be subject to Grants of Options, or transferred on account of other Grants or Awards under the Plan may not exceed 4.5 million shares. The shares may be authorized but unissued shares of Company Stock or reacquired shares of Company Stock, including shares purchased by the Company on the open market for purposes of the Plan. If and to the extent (i) Options or SARs granted under the Plan terminate, expire, or are canceled, forfeited, exchanged or surrendered without having been exercised (other than for reasons of the Exercise Price of the Option being less than the current Fair Market Value thereof), or (ii) any shares of Restricted Stock, RSUs or Performance Units are forfeited, or (iii) Company Stock, including RSUs, are used by the Participant to pay withholding taxes or as payment for the Exercise Price of the Grant, then the shares not made the subject of Grants and Awards, and the shares subject to such terminated, expired, canceled, forfeited, exchanged or surrendered Grants and Awards shall again be available for purposes of the Plan in addition to the number of shares of Company Stock otherwise available for Grants and Awards. No Participant under the Plan may receive aggregate Grants and Awards in excess of one million shares over the term of the Plan.

(b) Adjustments. If there is any change in the number or kind of shares of Company Stock outstanding (i) by reason of a stock dividend, spinoff, recapitalization, stock split, or combination or exchange of shares, (ii) by reason of a merger, reorganization or consolidation in which NU is the surviving entity, (iii) by reason of a reclassification or change in par value, or (iv) by reason of any other extraordinary or unusual event affecting the outstanding Company Stock as a class without NU's receipt of consideration, or (v) otherwise in the event of an equity restructuring within the meaning of Statement of Financial Accounting Standards No. 123 (revised 2004), other than (x) any distribution of securities or other property by the Company to shareholders in a spin-off or split-off that does not qualify as a tax-free spin-off of split-up under Section 355 of the Code (or any successor provision of the Code) or (y) any cash dividend (other than an extraordinary cash dividend or distribution), then the maximum number of shares of Company Stock available for Grants, the number of shares covered by outstanding Grants, the kind of shares issued under the Plan, and the price per share or the applicable market value of such Grants, including the per share exercise price of Options and Stock Appreciation Rights, shall be appropriately adjusted by the Committee to reflect any increase or decrease in the number of, or change in the kind or value of, issued shares of Company Stock to preclude, to the extent practicable, the enlargement or dilution of rights and benefits under such Grants; provided, however, that any fractional shares resulting from such adjustment shall be eliminated. Any increase to the number or kind of shares of Company Stock outstanding under this Article IX(1)(b) occurring on or after May 9, 2007 shall result in the adjustment in the 4.5 million shares authorized under Article IX(1)(a). No such adjustment shall be required to reflect the events described in clauses (x) and (y) above, or any other change in capitalization that does not constitute an equity restructuring; however, such adjustment may be made if the Committee determines that such adjustment is appropriate. Any adjustments determined by the Committee shall be final, binding and conclusive.

(c) Minimum Vesting Requirement. Grants of Restricted Stock or RSUs made pursuant to the Plan shall vest ratably no sooner than the first business day of each of the three years following the calendar year of the Grant. Grants of Options shall vest no sooner than the first business day of the year following the calendar year of the Grant. The Committee may, in its discretion, determine such other vesting schedule as it deems appropriate, except that any such other vesting schedule must fulfill at least the applicable minimum requirements set forth in the prior two sentences. The Committee may provide for complete or partial exceptions to these requirements as it deems appropriate in the case of a Participant whose service with the Company ends for reason of Retirement, Death, or Disability, or in the case of a Grant to a Non-Employee Trustee or a newly-hired Employe e, or upon a Change of Control of NU.

ARTICLE X
OPERATING RULES

1. Withholding of Taxes. All Grants under the Plan shall be subject to applicable federal (including FICA), state and local tax withholding requirements. The Company shall have the right to deduct from all Grants paid in cash, or from other wages paid to the Grantee, any federal, state or local taxes required by law to be withheld with respect to such Grants. In the case of Options and other Grants paid in Company Stock, the Company may require the Grantee or other person receiving such shares to pay to the Company the amount of any such taxes that the Company is required to withhold with respect to such Grants, or the Company may deduct from other wages paid by the Company the amount of any withholding taxes due with respect to such Grants. If the Committee so permits, a Grantee may elect to satisfy the Company's income tax withholding obligation with respect to an Option, SAR, Restricted Stock, Restricted Share Units or Performance Units that are paid in Company Stock, by having shares withheld up to an amount that does not exceed the Grantee's minimum applicable withholding tax rate for federal (including FICA), state and local tax liabilities. The election must be in a form and manner prescribed by the Committee.

2. Transferability of Grants.

(a) Nontransferability of Grants. Except as provided below, only the Grantee may exercise rights under a Grant during the Grantee's lifetime. A Grantee may not transfer those rights except by will or by the laws of descent and distribution or, with respect to Grants other than Incentive Stock Options, if permitted in any specific case by the Committee, pursuant to a domestic relations order (as defined under the Code or Title I of the Employee Retirement Income Security Act of 1974, as amended, or the regulations thereunder). When a Grantee dies, the personal representative or other person entitled to succeed to the rights of the Grantee ("Successor Grantee") may exercise such rights. A Successor Grantee must furnish proof satisfactory to the Company of his or her right to receive the Grant under the Grantee's will or under the applicable laws of descent and distribution.

(b) Transfer of Nonqualified Stock Options. Notwithstanding the foregoing, the Committee may provide, in a Grant Instrument, that a Grantee may transfer Nonqualified Stock Options to family members, one or more trusts for the benefit of family members, or one or more partnerships of which family members are the only partners, according to such terms as the Committee may determine; provided that the Grantee receives no consideration for the transfer of an Option and the transferred Option shall continue to be subject to the same terms and conditions as were applicable to the Option immediately before the transfer.

3. Requirements for Issuance or Transfer of Shares. No Company Stock shall be issued or transferred in connection with any Grant hereunder unless and until all legal requirements applicable to the issuance or transfer of such Company Stock have been complied with to the satisfaction of the Committee. The Committee shall have the right to condition any Grant made to any Grantee hereunder on such Grantee's undertaking in writing to comply with such restrictions on his or her subsequent disposition of such shares of Company Stock as the Committee shall deem necessary or advisable as a result of any applicable law, regulation or official interpretation thereof, and certificates representing such shares may be legended to reflect any such restrictions. Certificates representing shares of Company Stock issued or transferred under the Plan will be subject to such stop-transfer orders and other restrictions as may be required by applicable laws, regulations and interpretations, including any requirement that a legend be placed thereon.

4. Funding of the Plan. This Plan shall be unfunded. The Company shall not be required to establish any special or separate fund or to make any other segregation of assets to assure the payment of any Grants under this Plan. In no event shall interest be paid or accrued on any Grant, including unpaid installments of Grants.

5. Rights of Participants. Nothing in this Plan shall entitle any Employee or Non-Employee Trustee or other person to any claim or right to be granted a Grant under this Plan except as provided in Article V. Neither this Plan nor any action taken hereunder shall be construed as giving any individual any rights to be retained by or in the employ of the Company or any other employment rights, nor shall they interfere in any way with the right of the Company, a subsidiary or an affiliate to terminate the employment of any Employee at any time.

6. No Fractional Shares. No fractional shares of Company Stock shall be issued or delivered pursuant to the Plan or any Grant. The Committee shall determine whether cash, other awards or other property shall be issued or paid in lieu of such fractional shares or whether such fractional shares or any rights thereto shall be forfeited or otherwise eliminated.

7. Headings. Section headings are for reference only. In the event of a conflict between a title and the content of a Section, the content of the Section shall control.

8. Effective Date of the Plan. Subject to approval by NU's shareholders, the Plan as amended and restated, is effective on May 9, 2007.

9. Definition of Company. "Company" means NU and any Affiliate which is authorized by the Board to adopt the Plan and cover its eligible employees and whose designation as such has become effective upon acceptance of such status by the board of directors of the Affiliate. An Affiliate may revoke its acceptance of such designation at any time, but until such acceptance has been revoked, all the provisions of the Plan, including the authority of the Board and the Committee, and amendments thereto shall apply to the eligible employees of the Affiliate. In the event the designation is revoked by the board of directors of an Affiliate, the Plan shall be deemed terminated only with respect to such Affiliate. For the purposes hereof, "Affiliate" means each direct and indirect affiliated company that directly or through one or more intermediaries, controls, is controlled by, or is under common control w ith NU.

ARTICLE XI
CHANGE OF CONTROL OF NU

1. Change of Control of NU.

As used herein, a "Change of Control" shall be deemed to have occurred:

(i) When any "person," as such term is used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), other than the Company, its affiliates, or any Company or NU employee benefit plan (including any trustee of such plan acting as trustee), is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of NU representing more than 20% of the combined voting power of either (i) the then outstanding common shares of NU (the "Outstanding Common Shares") or (ii) the then outstanding voting securities of NU entitled to vote generally in the election of directors (the "Voting Securities"); or

(ii) Individuals who, as of the beginning of any twenty-four month period, constitute the Trustees (the "Incumbent Trustees") cease for any reason to constitute at least a majority of the Trustees or cease to be able to exercise the powers of the majority of the Trustees, provided that any individual becoming a trustee subsequent to the beginning of such period whose election or nomination for election by the Company's stockholders was approved by a vote of at least a majority of the trustees then comprising the Incumbent Trustees shall be considered as though such individual were a member of the Incumbent Trustees, but excluding, for this purpose, any such individual whose initial assumption of office is in connection with an actual or threatened election contest relating to the election of the Trustees of NU (as such terms are used in Rule 14a-1 1 of Regulation 14A promulgated under the Exchange Act); or

(iii) Consummation by NU of a reorganization, merger or consolidation (a "Business Combination"), in each case, with respect to which all or substantially all of the individuals and entities who were the respective beneficial owners of the Outstanding Common Shares and Voting Securities immediately prior to such Business Combination do not, following consummation of all transactions intended to constitute part of such Business Combination, beneficially own, directly or indirectly, more than 75% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation, business trust or other entity resulting from or being the surviving entity in such Business Combination in substantially the same proportion as their ownership immediately prior to such Busin ess Combination of the Outstanding Common Shares and Voting Securities, as the case may be; or

(iv) Consummation of a complete liquidation or dissolution of NU or sale or other disposition of all or substantially all of the assets of NU other than to a corporation, business trust or other entity with respect to which, following consummation of all transactions intended to constitute part of such sale or disposition, more than 75% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, is then owned beneficially, directly or indirectly, by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Common Shares and Voting Securities immediately prior to such sale or disposition in substantially the same proportion as their ownership of the

Outstanding Common Shares and Voting Securities, as the case may be, immediately prior to such sale or disposition.

2. Consequences of a Change of Control.

(a) Notice. Upon a Change of Control, the Company shall provide each Grantee with outstanding Grants written notice of such Change of Control.

(b) Assumption of Grants. Upon a Change of Control where the Company is not the surviving corporation (or survives only as a subsidiary of another corporation), unless the Committee determines otherwise, all outstanding Options and SARs that are not exercised and all outstanding restricted shares, restricted share units and Performance Units that are denominated in shares of Company Stock shall be assumed by, or replaced with comparable options, rights or entitlements by, the surviving corporation.

(c) Other Alternatives. Notwithstanding the foregoing, subject to subsection (d) below, in the event of a Change of Control, the Committee may take any of the following actions: the Committee may (i) require that Grantees surrender their outstanding Options, SARs, restricted shares, restricted share units and Performance Units that are denominated in shares of Company Stock in exchange for a payment by the Company, in cash or Company Stock as determined by the Committee, in an amount equal to the restricted shares, restricted share units or Performance Units (based on the then Fair Market Value of shares of Company Stock), or with respect to unexercised Options or SARs, in the amount by which the then Fair Market Value of the shares of Company Stock subject to the Grantee's unexercised Options and SARs exceeds the Exercise Price of the Options or the base amount of the SARs, as applicable, or (ii) after giving Gran tees an opportunity to exercise their outstanding Options and SARs, terminate any or all unexercised Options and SARs at such time as the Committee deems appropriate. Such surrender or termination shall take place as of the date of the Change of Control or such other date as the Committee may specify.

(d) Committee. The Committee making the determinations under this Article XI, Section 2(d) following a Change of Control must comprise the same members as those on the Committee immediately before the Change of Control. If the Committee members do not meet this requirement, the automatic provisions of Subsections (a) and (b) shall apply, and the Committee shall not have discretion to vary them.

(e) Limitations. Notwithstanding anything in the Plan to the contrary, in the event of a Change of Control, the Committee shall not have the right to take any actions described in the Plan (including without limitation actions described in Subsection (c) above) that would make the Change of Control ineligible for pooling of interests accounting treatment or that would make the Change of Control ineligible for desired tax treatment if, in the absence of such right, the Change of Control would qualify for such treatment and the Company intends to use such treatment with respect to the Change of Control.

ARTICLE XII
AMENDMENT AND TERMINATION

1. Amendment and Termination of the Plan.

(a) Amendment. The Board or the Committee may amend or terminate the Plan at any time; provided, however, that neither the Board nor the Committee shall amend the Plan without shareholder approval if such approval is required by Sections 162(m) or 422 of the Code.

(b) Termination of the Plan. The Plan shall terminate on the day preceding the tenth anniversary of its effective date, unless the Plan is terminated earlier by the Board or the Committee, or is extended by the Board or the Committee with the approval of the shareholders.

(c) Termination and Amendment of Outstanding Grants. A termination or amendment of the Plan that occurs after a Grant is made shall not materially impair the rights of a Grantee unless the Grantee consents, unless the Committee acts under Article XI, Section 2(c), or unless the amendment or termination is required under statute, regulation, other law, or rule of a governing or administrative body having the effect of a statute or regulation. The termination of the Plan shall not impair the power and authority of the Committee with respect to an outstanding Grant.

(d) Governing Document. The Plan shall be the controlling document. No other statements, representations, explanatory materials or examples, oral or written, may amend the Plan in any manner. The Plan shall be binding upon and enforceable against the Company and its successors and assigns.

ARTICLE XIII
MISCELLANEOUS

1. Grants in Connection with Corporate Transactions and Otherwise. Nothing contained in this Plan shall be construed to (i) limit the right of the Committee to make Grants under this Plan in connection with the acquisition, by purchase, lease, merger, consolidation or otherwise, of the business or assets of any corporation, firm or association, including Grants to employees thereof who become Employees of the Company, or for other proper corporate purposes, or (ii) limit the right of the Company to grant stock options or make other awards outside of this Plan. Without limiting the foregoing, the Committee may make a Grant to an employee of another corporation who becomes an Employee by reason of a corporate merger, consolidation, acquisition of stock or property, reorganization or liquidation involving the Company or any of its subsidiaries in substitution for a stock option or restricted s tock grant made by such corporation. The terms and conditions of the substitute grants may vary from the terms and conditions required by the Plan and from those of the substituted stock incentives. The Committee shall prescribe the provisions of the substitute grants.

2. Compliance with Law. The Plan, the exercise of Options and SARs and the obligations of the Company to issue or transfer shares of Company Stock under Grants shall be subject to all applicable laws and to approvals by any governmental or regulatory agency as may be required. With respect to persons subject to section 16 of the Exchange Act, it is the intent of the Company that the Plan and all transactions under the Plan comply with all applicable provisions of Rule 16b-3 or its successors under the Exchange Act. In addition, it is the intent of the Company that the Plan and, applicable Grants under the Plan comply with the applicable provisions of sections 162(m) and 422 of the Code, and any other applicable law or regulation having the effect of law. To the extent that any legal requirement of section 16 of the Exchange Act or section 162(m) or 422 of the Code as set forth in the Plan c eases to be required under section 16 of the Exchange Act or section 162(m) or 422 of the Code, that Plan provision shall cease to apply. The Committee may revoke any Grant if it is contrary to law or modify a Grant to bring it into compliance with any valid and mandatory government regulation. The Committee may also adopt rules regarding the withholding of taxes on

payments to Grantees. The Committee may, in its sole discretion, agree to limit its authority under this Section.

3. Deferred Compensation. Any deferrals made under the Plan, including awards granted under the Plan that are considered to be deferred compensation, must satisfy the requirements of Section 409A of the Internal Revenue Code to avoid adverse tax consequences to participating employees. These requirements include limitations on election timing, acceleration of payments, and distributions. The Company intends to structure any deferrals and awards under the Plan to meet the applicable tax law requirements.

4. Payment of Awards. The Committee, either at the time of Grant or by subsequent amendment, may require or permit deferral of the payment of Awards or Grants under such rules and procedures as it may establish.

5. Clawback. Upon written demand of the Company, an Employee will reimburse or forfeit all or a portion of any Award or Grant paid to the Employee under the Plan where: (i) payment of the Award or Grant was predicated on the achievement of certain financial results that were subsequently the subject of a substantial restatement of the financial statements of the Company, (ii) in the judgment of the Board the Employee engaged in fraud or misconduct that caused or partially caused the need for the substantial restatement, and (iii) a lower payment would have been made to the Employee based on the restated financial results. In the event the Employee fails to make prompt reimbursement of any such Award or Grant previously paid or delivered, the Company may, to the extent permitted by applicable law, deduct the amount required to be reimbursed from the Grantee's compensatio n otherwise due from the Company; provided, however, that the Company will not seek to recover upon Awards or Grants paid more than three years prior to the date the applicable restatement is disclosed.

6. Governing Law. The validity, construction, interpretation and effect of the Plan and Grant Instruments issued under the Plan shall exclusively be governed by and determined in accordance with the law of the State of placeStateConnecticut.

7. Disclaimer of Liability. The Declaration of Trust of NU provides that no shareholder of NU shall be held to any liability whatever for the payment of any sum of money, or for damages or otherwise under any contract, obligation or undertaking made, entered into or issued by the Board or by any officer, agent or representative elected or appointed by the Board, and no such contract, obligation or undertaking shall be enforceable against the Board or any of them in their or his or her individual capacities or capacity and all such contracts, obligations and undertakings shall be enforceable only against the Board as such, and every person or entity, having any claim or demand arising out of any such contract, obligation or undertaking shall look only to the trust estate for the payment or satisfaction thereof.

ARTICLE XIV
DEFINITIONS

When used herein, each of the following terms shall have the corresponding meaning set forth below unless a different meaning is plainly required by the context in which a term is used:

14.1 "Award" is an annual incentive award made to an Employee as provided in Article III.

14.2 "Cause" is described in Article IV(3)(e)(ii)(A).

14.3 "Change of Control" is described in Article XI(1).

14.4 "Code" is the Internal Revenue Code of 1986, as amended from time to time, and any successor thereto.

14.5 "Committee" is described in Article 11(1).

14.6 "Company Stock" or "Stock" is Northeast Utilities common shares, as described in Article IX(1)(a).

14.7 "Company" or "NU" is described in Article X.

14.8 "Disability" is described in Article IV(3)(e)(ii)

(B).

14.9 "Exchange Act" is the Securities Exchange Act of 1934, as amended from time to time, and any successor thereto.

14.10 "Exercise Price" is described in Article IV(3)(b)(ii).

14.11 "Fair Market Value" is, as of any given date, the value of Company Stock, as provided in Article IV(3)(b)(iii), or as otherwise determined by the Committee.

14.12 "Grant" is described in Article IV(1).

14.13 "Grantee" is the individual to whom a Grant is made, as provided in Article IV, Section 2(b).

14.14 "Grant Instrument" is described in Article IV(1).

14.15 "Incentive Stock Option" is described in Article IV(3)(b).

14.16 "Nonqualified Stock Option" is described in Article IV(3)(b).

14.17 "Option" is an Incentive Stock Option or a Nonqualified Stock Option, as described in Article IV(3)(b).

14.18 "Participant" is any eligible individual to whom an Award or Grant is made.

14.19 "Performance Goals" means the objectives for the Company or any subsidiary or affiliate or any unit thereof or any individual that may be established by the Committee for a Performance Period with respect to any performance-based Awards or Grants contingently awarded under the Plan. The Performance Goals for Awards or Grants that are intended to constitute "performance-based" compensation within the meaning of Section 162(m) (or any amended or successor provision) of the Code shall be based on one or more of the following criteria, either individually, alternatively or in any combination, and subject to such modifications or variations as specified by the Committee, applied to either the Company as a whole or to a business unit or subsidiary entity thereof, either individually, alternatively or in any combination, and measured over a period of time including any portion of a year, annually or cumulatively over a period of years, on an absolute basis or relative to a pre-established target, to previous years' results or to a designated comparison group, in each case as

specified by the Committee: cash flow; cash flow from operations; earnings (including, but not limited to, earnings before interest, taxes, depreciation and amortization or operating earnings); earnings per share, diluted or basic; earnings per share from continuing operations; net asset turnover; inventory turnover; capital expenditures; debt; debt reduction; credit rating; working capital; return on investment; return on sales; net or gross sales; market share; economic value added; cost of capital; change in assets; expense reduction levels; unit volume; productivity; delivery performance; service levels; safety record; stock price; return on equity; total shareholder return; return on capital; return on assets or net assets; revenue; income or net income; operating income or net operating income; operating profit or net operating profit; gross margin, operating margin or profit margin; and completion of acquisitions, divestitures, busi ness expansion, product diversification, new or expanded market penetration and other non-financial operating and management performance objectives, or other strategic business criteria consisting of one or more objectives based on satisfaction of specified revenue goals, geographic business expansion goals or cost targets.

With respect to awards that are intended to qualify as performance-based compensation within the meaning of Section 162(m) and to the extent consistent with Section 162(m) of the Code and the regulations promulgated thereunder, the Committee may, unless otherwise determined by the Committee at the time the Performance Goals are established, adjust the Performance Goals to exclude the effect of any of the following events that occur during a Performance Period: the impairment of tangible or intangible assets; litigation or claim judgments or settlements; changes in tax law, accounting principles or other such laws or provisions affecting reported results; business combinations, reorganizations and/or restructuring programs that have been approved by the Board; reductions in force and early retirement incentives; and any extraordinary, unusual, infrequent or non-recurring items separately identifi ed in the financial statements and/or notes thereto in accordance with generally accepted accounting principles. Notwithstanding the foregoing and with respect to awards that are not intended to qualify as performance-based compensation within the meaning of Section 162(m) of the Code, the Committee may, in its discretion, adjust Performance Goals as it considers necessary or appropriate.

14.20 "Performance Period" is the period selected by the Committee during which the performance of the Company or any subsidiary, affiliate or unit thereof or any individual is measured for the purpose of determining the extent to which an Award or Grant subject to Performance Goals or time vesting has been earned.

14.21 "Performance Unit" is described in Article VIII(1)(a).

14.22 "Plan" is this Northeast Utilities Incentive Plan, as amended from time to time.

14.23 "Qualified Performance-Based Compensation" is described in Article VIII(1)(e).

14.24 "Restriction Period" is described in Article VI(1)(a) and (2)(a). 14.25 "Restricted

Stock" is a Grant described in Article VI. 14.26 "Restricted Share Units" or "RSUs" is a

Grant described in Article VI. 14.27 "Retired" is described in Article IV(3)(e)(ii)(D).

14.28 "Stock Appreciation Right" or "SAR" is a right granted pursuant to Article VII.

Exhibit 10.27.9

AMENDMENT NO. 9 TO
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
FOR OFFICERS OF NORTHEAST UTILITIES SYSTEM COMPANIES

The Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Companies, as amended, is further amended, effective January 1, 1992, as follows:

Paragraph 2 of Article VII of the Plan is amended to read in its entirety as follows:

The normal form in which a Target Benefit shall be paid is, for a Participant who is unmarried on the date on which benefit payments are to commence as determined above, monthly payments on the first day of each month for the life of the Participant only, and for a Participant who is married at such time, monthly payments on the first day of each month for the life of the Participant and after the Participant's death, monthly payments on the first day of each month to the Participant's surviving spouse for life, each in an amount equal to 50 percent of the Participant's monthly payment. To be entitled to a Target Benefit under the Plan, a spouse must be married to the Participant both on the date Target Benefit payments to the Participant commence and on the Participant's date of death (hereinafter referred to as a "Surviving Spouse"). The annual Target Benefit payable to a married Participant, while living, shall be equal to the annual Target Benefit that would be payable to such Participant if un married.

Ratio of Earnings to Fixed Charges

Exhibit 12

(In thousands)

Earnings, as defined:	Years Ended December 31, 2007	2006	2005	2004	2003
Net income/(loss) from continuing operations before cumulative effect of accounting change	$ 245,896	$ 132,936	$ (256,903)	$ 70,423	$ 77,105
Income tax expense/(benefit)	109,420	(76,326)	(184,862)	22,388	19,751
Equity in earnings of regional nuclear generating and transmission companies	(3,983)	(334)	(3,311)	(2,592)	(4,487)
Dividends received from regional equity investees	4,542	2,145	687	3,879	8,904
Fixed charges, as below	264,311	258,682	260,428	236,324	228,764
Preferred dividend security requirements of consolidated subsidiaries	(9,265)	(9,265)	(9,265)	(9,265)	(9,265)
Total earnings/(loss), as defined	$ 610,921	$ 307,838	$ (193,226)	$ 321,157	$ 320,772
Fixed charges, as defined:					
Interest on long-term debt	$ 162,841	$ 141,579	$ 131,870	$ 107,365	$ 88,700
Interest on rate reduction bonds	61,580	74,242	87,439	98,899	108,359
Other interest	15,824	22,375	19,276	8,586	10,254
Rental interest factor	8,533	5,300	6,733	7,067	7,366
Amortized premiums, discounts and capitalized expenses related to indebtedness	6,268	5,921	5,845	5,142	4,820
Preferred dividend security requirements of consolidated subsidiaries	9,265	9,265	9,265	9,265	9,265
Total fixed charges, as defined	$ 264,311	$ 258,682	$ 260,428	$ 236,324	$ 228,764
Ratio of Earnings to Fixed Charges	2.31	1.19	(0.74) (a)	1.36	1.40

(a) Earnings were inadequate to cover fixed charges by $453.7 million for the year ended December 31, 2005.

2007 Annual Report
Northeast Utilities and Subsidiaries

Management's Discussion and Analysis of
Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the related notes included in this exhibit to our Form 10-K. References in this exhibit to "NU" or "the company" are to Northeast Utilities, and the terms "we," "us" and "our" refer to NU. All per share amounts are reported on a fully diluted basis.

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

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

Financial Condition and Business Analysis

Executive Summary

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

Results, Strategy and Outlook:

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

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

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

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

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

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

- We project consolidated 2008 earnings of between $1.65 per share and $1.90 per share, including earnings of between $1.05 per share and $1.15 per share at our distribution and generation segments and between $0.75 per share and $0.85 per share

at our transmission segments. We also project breakeven results in our remaining competitive businesses and a loss of between $0.10 per share and $0.15 per share for NU parent and other companies.

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

Legislative, Legal and Regulatory Items:

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

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

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

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

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

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

Liquidity:

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

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

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

- We had consolidated operating cash flows in 2007 of $248.4 million, compared with $407.1 million in 2006. Excluding the federal and state income tax payments of approximately $400 million in 2007 related to the 2006 sale of the competitive generation business, our consolidated operating cash flows were approximately $650 million in 2007, which is an increase of

approximately $243 million from 2006. This improvement was partially due to an expected reduction in regulatory refunds paid to CL&P customers during 2007 as compared to 2006. In addition, the regulated companies made lower payments to Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company (MYAPC) and Yankee Atomic Electric Company (YAEC) (the Yankee Companies) for nuclear decommissioning and closure costs in 2007 as compared to 2006. Also impacting cash flows from operations were lower cash payments related to Select Energy, Inc.'s (Select Energy) derivative contracts and changes in working capital items related to the divestiture of NU Enterprises' businesses in 2006.

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

Overview

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

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

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

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

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

*After preferred dividends in all years.

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

CL&P's 2007 distribution segment earnings were $86.2 million lower than in 2006 primarily because of the $74 million reduction in income tax expense pursuant to the PLR received from the IRS in 2006 related to the treatment of excess deferred income taxes (EDIT) and unamortized tax credits in connection with the sale of CL&P's former generating plants. Excluding the impact of the PLR on 2006 earnings, CL&P's 2007 distribution segment earnings were $12.2 million lower than in 2006. This decrease in earnings was primarily due to the $7.7 million after-tax benefit in 2006 related to the sale to a third party of competitive generation assets that CL&P had previously sold to its affiliate, Northeast Generation Company (NGC); the absence in 2007 of a fixed procurement fee of approximately $6.6 million (after-tax) that expired at the end of 2006; higher operations and maintenance expense; higher inte rest expense; and higher income tax expense, partially offset by a $7 million distribution rate increase that took effect on January 1, 2007 and a 1.7 percent increase in sales. CL&P's distribution segment Regulatory ROE was 7.9 percent for 2007 and 7.5 percent for 2006**.** We expect CL&P's distribution segment Regulatory ROE will be in the 8 percent to 8.5 percent range in the first full year of new rates

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Future Outlook

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

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

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

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

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

Liquidity

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Business Development and Capital Expenditures

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

Regulated Companies:

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

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

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

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

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

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

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

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

the 115 KV Springfield Underground Cables project referred to below. The CWIP amounts included in rate base for these projects are $242 million, $124 million, $238 million, $437 million, and $450 million, respectively, for the 2008 to 2012 periods.

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

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

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

- A 69-mile, 345 KV/115 KV transmission project from Middletown to Norwalk, Connecticut. CL&P's portion of this project is estimated to cost approximately $1.05 billion. At December 31, 2007, CL&P's portion of this project was approximately 62 percent complete and by the end of February of 2008, was approximately 70 percent complete. As of December 31, 2007, CL&P had capitalized $593 million associated with this project. Although the project is scheduled to be completed at the end of 2009, construction of the project is currently ahead of schedule, and CL&P has reviewed the remaining work to determine whether it can be completed at an earlier date. As a result of this review, we now expect to complete this project in mid-2009. This early completion date would not have a significant impact on our earnings guidance.

- A two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), construction of which began in October of 2006. This project is estimated to cost approximately $223 million. This project is scheduled to be completed by the end of 2008. At December 31, 2007, this project was approximately 69 percent complete, and at the end of February of 2008, was approximately 74 percent complete. As of December 31, 2007, CL&P had capitalized $133 million associated with this project.

- The replacement of the 138 KV 11-mile undersea electric transmission cable between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable). CL&P and the Long Island Power Authority each own approximately 50 percent of the line. CL&P's portion of the project is estimated to cost $72 million. After the final regulatory permits were received, marine construction activities commenced in October of 2007, and the project is expected to be placed in service in the second half of 2008. The pre-existing cables were decommissioned in September of 2007, and approximately 94 percent of the cables was removed as of December 31, 2007, including all portions located in Connecticut. Installation of the new cable began in early February of 2008. At December 31, 2007, the project was approximately 63 percent complete, and at the end of February of 2008, was a pproximately 72 percent complete. As of December 31, 2007, CL&P had capitalized $45 million associated with this project, including the cost of the new cable, which was delivered in the fourth quarter of 2007.

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

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

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

Assuming that virtually all of the 345 KV portions of the NEEWS Overhead project are constructed overhead and on existing rights of way, we are maintaining our estimate of our share of the cost of the NEEWS Overhead project at approximately $1.05 billion. We are also maintaining our estimate of the cost of the Springfield Underground Cables project at approximately $350 million at this time. However, as we continue to review the designs of the NEEWS Overhead project and the Springfield Underground Cables project with

ISO-NE over the coming months, we expect these figures to change. We anticipate that we will have additional information on the scope and costs of these projects by mid-2008.

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

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

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

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

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

Transmission Rate Matters and FERC Regulatory Issues

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

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

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

Pursuant to this FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. On August 27, 2007, we submitted a revised compliance filing with the other New England transmission owners, which outlined the

regional refund process to comply with the FERC's July 26, 2007 order. In addition, the transmission owners filed a request for rehearing claiming that the FERC improperly set the floor for refunds based on the lower rates that the FERC approved in its October 31, 2006 order, rather than the last approved rates, for the period from June 3, 2005 to September 3, 2006. The FERC denied this request on January 17, 2008, and the transmission owners have until March 17, 2008 to appeal, if they so choose.

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

Legislative Matters

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

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

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

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

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

Connecticut:

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

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

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

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

New Hampshire:

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

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

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

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

Regulatory Developments and Rate Matters

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

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

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

Connecticut - CL&P:

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

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

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

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

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

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

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

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

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

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

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

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

Connecticut - Yankee Gas:

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

New Hampshire:

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

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

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

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

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

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

Massachusetts:

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

Contingent Matters:

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

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

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

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

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

Deferred Contractual Obligations

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

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

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

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

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

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

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same periods as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related t o disallowed spent nuclear fuel pool operating expenses.

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

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

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

NU Enterprises Divestitures

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

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

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

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

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

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

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

NU Enterprises Contracts

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

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

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

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

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

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

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

(Millions of Dollars)

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

(Millions of Dollars)

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

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

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

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

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

Off-Balance Sheet Arrangements

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

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

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

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

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

Enterprise Risk Management

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

Critical Accounting Policies and Estimates

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

incurred. If we determine that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that we record the charge in earnings at that time.

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

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

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

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

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

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

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

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

Actuarial Determination of Expense*:* We base the actuarial determination of Pension Plan and PBOP Plan expense on a market-related value of assets (MRVA), which reduces year-to-year volatility. This MRVA calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the MRVA and the actual return based on the fair value of assets. At December 31, 2007, total investment gains to be recognized in the MRVA over the next four years are $106.7 million and $1.5 million**,** for the Pension Plan and the PBOP Plan, respectively. As these asset gains are reflected in MRVA over the next four years, they will be subject to amortization with other unrecognized gains/losses. The Plans currently amortize unrecognized gains/losses as a compo nent of pension and PBOP expense over 12 years, which is the average future service lives of the employees at December 31, 2007. At December 31, 2007, the net actuarial loss subject to amortization over the next 12 years was $65.2 million and $109.6 million, respectively, which excludes

$106.7 million and $1.5 million of previous investment gains not currently reflected in the MRVA for the Pension Plan and PBOP Plan, respectively.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Other Matters

Consolidated Edison, Inc. Merger Litigation:

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

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

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

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

Accounting Standards Issued But Not Yet Adopted:

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

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

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

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 is effective in the first quarter of 2008, with the effect of application to eligible items as of January 1, 2008 required to be reflected as a cumulative-effect adjustment to the opening balance of retained earnings. If a company elects the fair value option for an eligible item, changes in that item's fair value at subsequent reporting dates must be recognized in earnings. We are currently evaluating whether or

not to elect the fair value option for our securities held in trust as of January 1, 2008. As of January 1, 2008, securities held in trust for the Supplemental Executive Retirement Plan (SERP) and non-SERP benefit plans had unrealized gains included in accumulated other comprehensive income of approximately $3 million after taxes that would be recorded as a cumulative-effect adjustment to retained earnings if SFAS No. 159 is implemented. Implementation of SFAS No. 159 for WMECO's securities held in its prior spent nuclear fuel trust is not expected to have a material effect on the financial statements.

Contractual Obligations and Commercial Commitments:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

RESULTS OF OPERATIONS

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

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

(a) Percent greater than 100.

2007 Compared to 2006

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

Operating Revenues

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

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

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

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

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

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

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

Lower regulated company distribution and transmission segment expenses of $49 million are primarily due to lower reliability must run (RMR) expenses at CL&P ($133 million), partially offset by higher Energy Independence Act (EIA) expenses which are tracked and recovered through the regulatory tracking mechanisms ($29 million), higher administration and general expenses at CL&P, WMECO and PSNH ($22 million), higher retail transmission expenses at PSNH and WMECO ($21 million) and Summer Savings Rewards Program which was implemented in 2007 at CL&P as a result of a legislative act ($14 million).

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

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

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

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

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

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

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

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

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

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

Income/(Loss) from Discontinued Operations
See Note 3, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements for a description and explanation of the discontinued operations.

2006 Compared to 2005

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

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

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

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

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

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

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

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

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

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

Higher distribution and transmission expenses of $80 million are primarily due to higher expenses that are recovered in the distribution regulatory rate tracking mechanisms. These costs include higher distribution RMR costs and other power pool related expenses ($63 million) and higher CL&P conservation and load management expenses of $15 million. Distribution and transmission general and

administrative expenses increased primarily due to higher employee related costs ($19 million), higher regulatory commission, outside service and other administrative costs ($6 million), partially offset by the absence of 2005 employee termination and benefit plan curtailment costs ($23 million) of which $21 million relates to regulated distribution that impact earnings.

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

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

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

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

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

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

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

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

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

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

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

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

Company Report on Internal Controls Over Financial Reporting

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

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

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

February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Northeast Utilities and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income/(loss), comprehensive income/(loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. We also have audited the Company's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accom panying 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 a ccepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
February 28, 2008

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

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

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

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

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME/(LOSS)

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

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

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

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

	Common Shares		Capital Surplus, Paid In	Deferred Contribution Plan ESOP	Retained Earnings	Accumulated Other Comprehensive (Loss)/ Income	Treasury Stock	Total
	Shares	Amount						
				(Thousands of Dollars, except share information)				
Balance as of January 1, 2005	129,034,442	$ 756,155	$ 1,116,106	$ (60,547)	$ 845,343	$ (1,220)	$ (359,126)	$ 2,296,711
Net loss for 2005					(253,488)			(253,488)
Dividends on common shares - $0.675 per share					(87,554)			(87,554)
Issuance of common shares, $5 par value	23,666,723	118,334	332,493					450,827
Allocation of benefits - ESOP	590,173		(2,161)	13,663				11,502
Change in restricted shares, net	(65,446)		5,295				(1,084)	4,211
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			368					368
Capital stock expenses, net			(14,540)					(14,540)
Other comprehensive income						21,207		21,207
Balance as of December 31, 2005	153,225,892	874,489	1,437,561	(46,884)	504,301	19,987	(360,210)	2,429,244
Net income for 2006					470,578			470,578
Dividends on common shares - $0.725 per share					(112,219)			(112,219)
Issuance of common shares, $5 par value	522,535	2,612	6,882					9,494
Allocation of benefits - ESOP	523,452		(618)	12,118				11,500
Change in restricted shares, net	(38,738)		4,293				(690)	3,603
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			1,112					1,112
Capital stock expenses, net			356					356
Adjustment to funded status of pension, SERP and other post retirement plans (SFAS No. 158)						(4,246)		(4,246)
Other comprehensive loss						(11,243)		(11,243)
Balance as of December 31, 2006	154,233,141	877,101	1,449,586	(34,766)	862,660	4,498	(360,900)	2,798,179
Adoption of FIN48 - accounting for uncertainty of income taxes					(41,816)			(41,816)
Net income for 2007					246,483			246,483
Dividends on common shares - $0.775 per share					(120,535)			(120,535)
Issuance of common shares, $5 par value	504,455	2,522	6,534					9,056
Allocation of benefits - ESOP	363,470		2,129	8,414				10,543
Change in restricted shares, net	(21,104)		4,368				(627)	3,741
Change in treasury stock	(192)		6				(6)	-
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			3,183					3,183
Capital stock expenses, net			140					140
Other comprehensive income						4,861		4,861
Balance as of December 31, 2007	155,079,770	$ 879,623	$ 1,465,946	$ (26,352)	$ 946,792	$ 9,359	$ (361,533)	$ 2,913,835

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

A. About Northeast Utilities

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

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

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

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

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

B. Presentation

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

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

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

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

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

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

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

C. Accounting Standards Issued But Not Yet Adopted

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

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

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

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

D. Revenues

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

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

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

Regulated Companies' Transmission Revenues - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of NU’s wholesale transmission revenues are collected under the New England Independent System Operator (ISO-NE) FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Local Network Service (LNS) rate schedules to recover transmission and other services. The RNS rate,

administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, administered by NU, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining three southwest Connecticut projects (Middletown-Norwalk, Glenbrook Cables and Long Island Replacement Cable). The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all regional and local revenue requirements as prescribed in Tarif f No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to retail customers. At December 31, 2007, the LNS rates were in an underrecovery position of approximately $23 million, which will be recovered from LNS customers in mid-2008. NU believes that these rates will provide it with timely recovery of transmission costs, including costs of its major transmission projects.

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

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

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

E. Derivative Accounting

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

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

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

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

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

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

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

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

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

F. Regulatory Accounting

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

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

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

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

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

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

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

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

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

Deferred Benefit Costs: On December 31, 2006, the company implemented SFAS No. 158, "Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans." SFAS No. 158 applies to NU’s Pension Plan, SERP, and postretirement benefits other than pension (PBOP) Plan and requires an additional benefit liability to be recorded with an offset to accumulated other comprehensive income in shareholders’ equity, which is remeasured annually. However, because the regulated companies are cost-of-

service rate regulated entities under SFAS No. 71, offsets were recorded as a regulatory asset of $201.4 million at December 31, 2007 and $407.4 million at December 31, 2006 as these amounts have been and continue to be recoverable in cost-of-service regulated rates. Regulatory accounting was also applied to the portions of the NUSCO costs that support the regulated companies, as these amounts are also recoverable. The majority of the deferred benefit costs are not in rate base.

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

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

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

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

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

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

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

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

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

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

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

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

G. Income Taxes

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

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

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

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

* Not meaningful.

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

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

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

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

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

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

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

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

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

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

- Interest on uncertain tax positions is recorded and classified as a component of other interest expense. NU recorded accrued interest expense of $19.4 million, which is included in the cumulative effect of a change in accounting principle, as of January 1, 2007. For the year ended December 31, 2007, NU recorded interest expense of $2.4 million. At December 31, 2007, $21.8 million of accrued interest expense was recognized on the accompanying consolidated balance sheet.

- No penalties have been recorded under FIN 48. If penalties are recorded in the future, then the estimated penalties would be classified as a component of other income/(loss), net.

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

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

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

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

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

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

H. Other Investments

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

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

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

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

I. Property, Plant and Equipment and Depreciation

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

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

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

J. Equity Method Investments

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

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

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

K. Allowance for Funds Used During Construction

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

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

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

L. Sale of Customer Receivables

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

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

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

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

M. Asset Retirement Obligations

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

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

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

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

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

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

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

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

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

N. Materials and Supplies

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

O. Cash and Cash Equivalents

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

P. Special Deposits

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

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

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

Q. Other Taxes

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

R. Other Income, Net

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

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

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

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

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

S. Supplemental Cash Flow Information

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

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

T. Marketable Securities

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

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

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

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

U. Provision for Uncollectible Accounts

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

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

2. Restructuring and Impairment Charges

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

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

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

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

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

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

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

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

3. Assets Held for Sale and Discontinued Operations

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

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

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

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

Summarized financial information for the discontinued operations is as follows:

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

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

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

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

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

4. Short-Term Debt

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

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

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

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

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

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

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

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

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

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

5. Derivative Instruments

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

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

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

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

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

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

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

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

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

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

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

- Charges of $7.4 million, $10.9 million and $419 million for the years ended December 31, 2007, 2006 and 2005, respectively, associated with the mark-to-market on, and changes in, the fair value of certain long-dated wholesale electricity contracts in New England, New York and PJM and contracts to purchase generation products in New York.

- A charge of $0.8 million for the year ended December 31, 2006 related to the fair value of certain asset-specific sales and forward sales of electricity at hub points for generation contracts. These contracts expired on December 31, 2006.

- A benefit of $30 million for the year ended December 31, 2005 associated with contracts previously designated as wholesale that were redesignated to support the retail marketing business.

- A charge of $36.4 million for the year ended December 31, 2005 for contract asset write-offs and a contract termination payment in March of 2005.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6. Employee Benefits

A. Pension Benefits and Postretirement Benefits Other Than Pensions

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

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

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

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

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

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

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

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

Market-Related Value of Pension Plan Assets: NU bases the actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets and are included in actuarial gains and losses. Since the market-related valuation calculation recognizes gains or losses over a four-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The components of net periodic benefit expense are as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(Millions of Dollars)

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

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

Contributions: Currently, NU's policy is to annually fund the Pension Plan in an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code. NU does not expect to make any

contributions to the Pension Plan in 2008. For the PBOP Plan, it is currently NU's policy to annually fund an amount equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits. NU contributed $38 million for the year ended December 31, 2007 to fund the PBOP Plan and expects to make $36.2 million in contributions to the PBOP Plan in 2008. Beginning in 2007, NU made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $3 million in 2007 and is estimated to be $4 million in 2008.

B. Defined Contribution Plans

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

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

C. Employee Stock Ownership Plan

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

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

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

D. Share-Based Payments

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

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

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

- For grants of restricted shares and restricted share units (RSUs), NU records compensation expense over the vesting period based upon the fair value of NU's common shares at the date of grant but records this expense net of estimated forfeitures.

- Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.

- NU has not granted any stock options since 2002, and no compensation expense has been recorded. All options were fully vested prior to January 1, 2006.

- For shares sold under the ESPP, an immaterial amount of compensation expense was recorded in the first quarter of 2006, and no compensation expense will be recorded in future periods as a result of a plan amendment that was effective on February 1, 2006.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

E. Other Retirement Benefits

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

7. Goodwill and Other Intangible Assets

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

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

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

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

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

8. Commitments and Contingencies

A. Regulatory Developments and Rate Matters

Connecticut:

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

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

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

Massachusetts:

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

B. Environmental Matters

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

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

These estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of

contamination at the site, the extent of NU's responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

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

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

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

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

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

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

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

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

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

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

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

mechanism to recover environmental costs from its customers, and changes in WMECO's environmental reserves impact WMECO's earnings. HWP does not have the ability to recover environmental costs in rates, and changes in HWP's environmental reserves impact HWP's earnings.

C. Spent Nuclear Fuel Disposal Costs

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

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

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

D. Long-Term Contractual Arrangements

Regulated Companies:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NU Enterprises:

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

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

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

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

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

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

E. Deferred Contractual Obligations

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

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

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

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

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

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

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

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

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

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

F. NRG Energy, Inc. Exposures

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

and 3) the recovery of, among other claimed damages, approximately $17.5 million of capital costs and expenses incurred by Yankee Gas related to an NRG subsidiary's generating plant construction project that has ceased.

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

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

G. Consolidated Edison, Inc. Merger Litigation

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

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

In a 2005 opinion, a panel of three judges at the Second Circuit held that NU shareholders had no right to sue Con Edison for its alleged breach of the parties' Merger Agreement. This ruling left intact the remaining claims between NU and Con Edison for breach of contract, which include NU's claim for recovery of costs and expenses of approximately $32 million and Con Edison's claim for damages of at least $314 million. Any damage award would include pre-judgment interest from the date of the filing of the claim. NU's request for a rehearing was denied in 2006. NU opted not to seek review of this ruling by the United States Supreme Court. In April of 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. On January 31, 2008, the trial judge denied a series of motions by both NU and Con Edison that had been pending for more than one year, including NU& #146;s motion for an order dismissing Con Edison's synergy damage claim. The judge ordered the parties to be trial ready on four days' notice beginning March 21, 2008. It is not possible for NU to predict either the outcome of this matter or its ultimate effect on NU.

H. Guarantees and Indemnifications

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

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

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

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

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

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

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

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

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

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

I. Transmission Rate Matters and FERC Regulatory Issues

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

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

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

J. Other Litigation and Legal Proceedings

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

9. Fair Value of Financial Instruments

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

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

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

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

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

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

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

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

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

10. Marketable Securities

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

11. Leases

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

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

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

operating lease payments was approximately $10.5 million, $10 million and $9.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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

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

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

12. Long-Term Debt

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

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

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

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

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

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

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

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

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

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

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

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

13. Dividend Restrictions

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

14. Accumulated Other Comprehensive Income/(Loss)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

15. Earnings Per Share

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

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

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

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

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

16. Segment Information

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

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

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

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

Effective on January 1, 2007, financial information for the remaining operations of HWP that were not exited as part of the sale of the competitive generation business was included as part of the Other reportable segment as these operations were no longer considered

part of NU Enterprises subsequent to the sale. Accordingly, HWP's remaining operations have been presented as part of the Other reportable segment for the year ended December 31, 2007.

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

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

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

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

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

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

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

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

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

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

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

	For the Year Ended December 31, 2005						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 4,836.5	$ 503.3	$ 167.5	$ 1,912.1	$ 353.0	$ (426.2)	$ 7,346.2
Restructuring and impairment charges	- -	- -	- -	(36.1)	- -	- -	(36.1)
Depreciation and amortization	(549.2)	(22.0)	(24.0)	(4.7)	(17.8)	13.6	(604.1)
Other operating expenses	(4,012.8)	(441.7)	(80.7)	(2,494.8)	(355.1)	426.9	(6,958.2)
Operating income/(loss)	274.5	39.6	62.8	(623.5)	(19.9)	14.3	(252.2)
Interest expense, net of AFUDC	(169.5)	(17.1)	(15.0)	(17.8)	(34.9)	15.7	(238.6)
Interest income	3.6	0.3	0.6	4.9	17.0	(19.2)	7.2
Other income, net	41.7	0.6	6.6	0.4	150.6	(152.5)	47.4
Income tax (expense)/benefit	(41.1)	(6.1)	(12.5)	234.4	18.4	(8.2)	184.9
Preferred dividends	(4.2)	-	(1.4)	-	-	-	(5.6)
Income/(loss) from continuing operations	105.0	17.3	41.1	(401.6)	131.2	(149.9)	(256.9)
Income from discontinued operations	- -	- -	- -	4.4	- -	- -	4.4
Income/(loss) before cumulative effect of accounting change	105.0	17.3	41.1	(397.2)	131.2	(149.9)	(252.5)
Cumulative effect of accounting change, net of tax benefit	- -	- -	- -	(1.0)	- -	- -	(1.0)
Net income/(loss)	$ 105.0	$ 17.3	$ 41.1	$ (398.2)	$ 131.2	$ (149.9)	$ (253.5)
Cash flows for total investments in plant (3)	$ 400.9	$ 74.6	$ 247.0	$ 23.2	$ 29.7	$ -	$ 775.4

(1) Includes PSNH generation activities.

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

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

Consolidated Statements of Quarterly Financial Data (Unaudited)

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

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

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

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

Selected Consolidated Financial Data (Unaudited)

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

(a) Includes portions due within one year, but excludes rate reduction bonds.
(b) Market price information reflects closing prices as reflected by the New York Stock Exchange.

Selected Consolidated Sales Statistics
(Unaudited)

	2007	2006	2005	2004	2003
Revenues: *(Thousands)*					
Regulated companies:					
Residential	$ 2,558,547	$ 2,409,414	$ 2,080,395	$ 1,707,434	$ 1,669,199
Commercial	1,735,923	1,977,444	1,727,278	1,429,608	1,411,881
Industrial	412,381	589,742	577,834	513,999	514,076
Wholesale	392,675	388,635	411,361	344,254	405,120
Streetlighting and Railroads	45,880	52,853	47,769	41,976	44,977
Miscellaneous and eliminations	84,043	133,925	159,402	143,431	(61,564)
Total Electric	5,229,449	5,552,013	5,004,039	4,180,702	3,983,689
Total Gas	514,185	453,894	503,303	407,812	361,470
Total - Regulated companies	$ 5,743,634	$ 6,005,907	$ 5,507,342	$ 4,588,514	$ 4,345,159
NU Enterprises:					
Retail	$ -	$ 583,829	$ 1,212,176	$ 857,355	$ 660,145
Wholesale	25,992	20,163	644,541	1,722,603	1,684,448
Generation	-	258,178	210,833	196,191	185,493
Services	68,324	39,887	102,327	117,500	96,963
Miscellaneous and eliminations	3,354	(243)	(257,750)	(245,745)	(223,440)
Total - NU Enterprises	$ 97,670	$ 901,814	$ 1,912,127	$ 2,647,904	$ 2,403,609
Other miscellaneous and eliminations	(19,078)	(30,034)	(73,243)	(755,734)	(851,694)
Total	$ 5,822,226	$ 6,877,687	$ 7,346,226	$ 6,480,684	$ 5,897,074
Regulated companies - Sales: *(KWH - Millions)*					
Residential	15,051	14,652	15,518	14,866	14,824
Commercial	15,103	14,886	15,234	14,710	14,471
Industrial	5,635	5,750	6,023	6,274	6,223
Wholesale	3,855	8,777	4,856	5,787	6,813
Streetlighting and Railroads	353	332	348	348	348
Total	39,997	44,397	41,979	41,985	42,679
Regulated companies - Customers: *(Average)*					
Residential	1,697,073	1,686,169	1,674,563	1,659,419	1,631,582
Commercial	189,727	188,281	195,844	194,233	186,792
Industrial	7,291	7,406	7,638	7,752	7,644
Streetlighting and Railroads	3,855	3,873	3,912	3,930	3,858
Total Electric	1,897,946	1,885,729	1,881,957	1,865,334	1,829,876
Gas	202,743	199,377	196,870	194,212	192,816
Total	2,100,689	2,085,106	2,078,827	2,059,546	2,022,692

2007 Annual Report
The Connecticut Light and Power Company

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the related notes included in this exhibit to our Form 10-K. References in this exhibit to "CL&P" or "the company" are to The Connecticut Light and Power Company, and the terms "we," "us" and "our" refer to CL&P.

The discussion below references our earnings, which at times excludes a reduction in 2006 income tax expense pursuant to a Private Letter Ruling (PLR) issued by the Internal Revenue Service (IRS). We use this measure not recognized under accounting principles generally accepted in the United States of America (GAAP) to more fully explain and compare the 2007 and 2006 results without the impact of this non-recurring item. This measure should not be considered as an alternative to our reported net income determined in accordance with GAAP as an indicator of our operating performance.

Financial Condition and Business Analysis

Executive Summary

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

Results:

- In 2007, we earned $133.6 million compared to $200 million in 2006 and $94.8 million in 2005. These earnings are stated before approximately $5.6 million of preferred dividends in each year. Included in earnings were transmission segment earnings of $68.2 million, $48.1 million and $30.7 million in 2007, 2006 and 2005, respectively, and distribution segment earnings of $65.4 million, $151.9 million and $64.1 million in 2007, 2006 and 2005, respectively. Results for 2006 included a reduction in income tax expense for the distribution segment of $74 million pursuant to a PLR received from the IRS.

- We have currently completed the majority of each of our three major transmission projects presently under construction in southwest Connecticut. Two of those projects are expected to be completed in 2008 and the third in 2009.

Legislative and Regulatory Items:

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

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

Liquidity:

- Our liquidity position in 2007 benefited from a capital contribution of $570.7 million from our parent company and the proceeds we received from the issuance of $500 million of long-term debt in 2007.

- Our cash capital expenditures totaled $826.2 million in 2007, compared with $567.2 million in 2006. The increase was primarily the result of higher transmission segment capital expenditures.

- We project a total of approximately $3.5 billion of capital expenditures from 2008 through 2012, including $872 million in 2008, of which $538 million is projected to be spent on transmission. Over the five-year period, approximately $2 billion is projected to be spent on transmission and approximately $1.5 billion on distribution.

- We had consolidated operating cash flows in 2007 of $199.7 million, compared with $251.4 million in 2006. This decrease was primarily due to a $257 million increase in income taxes paid in 2007 as compared to 2006, which was a result of the 2006 sale of NU's competitive generation business, as discussed further below under "Liquidity," partially offset by an expected reduction in regulatory refunds paid to our customers during 2007 as compared to 2006. This decrease was also offset by lower payments to Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company (MYAPC) and Yankee Atomic Electric Company (YAEC) (the Yankee Companies) for nuclear decommissioning and closure costs in 2007 as compared to 2006.

Overview

We are a wholly owned subsidiary of Northeast Utilities (NU). NU's other regulated electric subsidiaries include Public Service Company of New Hampshire and Western Massachusetts Electric Company.

In 2007, we earned $133.6 million, compared to $200 million in 2006 and $94.8 million in 2005. These results include transmission segment earnings of $68.2 million, $48.1 million, and $30.7 million in 2007, 2006 and 2005, respectively, and distribution earnings of $65.4 million, $151.9 million and $64.1 million in 2007, 2006 and 2005, respectively. These earnings are stated before approximately $5.6 million of preferred dividends in each year, including $4 million for distribution and $1.6 million for transmission in 2007, $4.3 million for distribution and approximately $1.3 million for transmission in 2006, and $4.2 million for distribution and $1.4 million for transmission in 2005. Results for 2006 included a reduction in income tax expense of $74 million pursuant to a PLR received from the IRS. Results for 2007 included a discretionary pre-tax donation to the NU Foundation, Inc. of $0.6 million.

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

Our 2007 distribution segment earnings, which do not include preferred dividends, were $86.5 million lower than in 2006 primarily because of the $74 million reduction in income tax expense pursuant to the PLR received from the IRS in 2006 related to the treatment of excess deferred income taxes (EDIT) and unamortized tax credits in connection with the sale of our former generating plants. Excluding the impact of the PLR on 2006 earnings, our 2007 distribution segment earnings were $12.5 million lower than in 2006. This decrease in earnings was primarily due to the $7.7 million after-tax benefit in 2006 related to the sale to a third party of competitive generation assets that we had previously sold to another subsidiary of NU; the absence in 2007 of a fixed procurement fee of approximately $6.6 million (after-tax) that expired at the end of 2006; higher operations and maintenance expense; higher interest expense; and high er income tax expense, partially offset by a $7 million distribution rate increase that took effect on January 1, 2007 and a 1.7 percent increase in sales. Our distribution segment Regulatory ROE was 7.9 percent for 2007 and 7.5 percent for 2006. We expect our distribution segment Regulatory ROE will be in the 8 percent to 8.5 percent range in the first full year of new rates beginning February 1, 2008, as a result of the DPUC's final decision in our distribution rate proceeding. Due to the February 2008 implementation of new rates, we expect a distribution segment Regulatory ROE of approximately 8 percent in calendar year 2008.

For our distribution segment, a summary of changes in our retail electric kilowatt-hour (KWH) sales for 2007 as compared to 2006 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)
Residential	2.8 %	0.4 %
Commercial	1.3 %	0.8 %
Industrial	(1.3)%	(1.5)%
Other	6.9 %	6.9 %
Total	1.7 %	0.4 %

A summary of our retail electric sales in gigawatt-hours for 2007 and 2006 is as follows:

	2007	2006	Percentage Increase/ (Decrease)
Residential	10,336	10,053	2.8 %
Commercial	10,128	9,995	1.3 %
Industrial	3,264	3,306	(1.3)%
Other	304	284	6.9 %
Total	24,032	23,638	1.7 %

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

Liquidity

During 2007, our liquidity position benefited from a capital contribution of $570.7 million from NU parent and the proceeds we received from the issuance of $500 million of long-term debt. At December 31, 2007, we had $20 million sold under our $100 million facility for the sale of accounts receivable.

We had consolidated operating cash flows in 2007 of $199.7 million, compared with $251.4 million in 2006 and $297.3 million in 2005. This decrease was primarily due to a $257 million increase in income taxes paid in 2007 as compared to 2006, which was a result of the 2006 sale of NU's competitive generation business. We accrued the majority of our portion of this tax obligation in 2000 upon the sale of these generation assets to another NU subsidiary, but due to the intercompany nature of the sales, the federal and state income tax payments were deferred at that time. It was not until NU ultimately sold these generation assets to an unaffiliated third party in November of 2006 that we were required to pay this deferred tax obligation. The increase in income taxes paid was partially offset by an expected reduction in regulatory refunds related to Competitive Transition Assessment (CTA) made to our customers durin g 2007 as compared to 2006. The change in CTA refunds and other regulatory collections or refunds amounted to approximately $85 million in cash flow improvements in 2007 compared to 2006. In addition to lower regulatory refunds paid, we made lower payments to the Yankee Companies for nuclear decommissioning and closure costs in 2007 as compared to 2006, primarily as a result of the extension of the collection period for decommissioning and closure costs at CYAPC, and had a positive change in working capital requirements.

In 2008, we project consolidated operating cash flows of approximately $380 million, rising to approximately $550 million in 2012 due to expected returns from our capital growth program. These projections assume that we receive timely recovery of our capital investments and purchased power costs through appropriate rates.

We issued $250 million in 30-year first mortgage bonds and $250 million in 10-year first mortgage bonds in 2007. The coupon rates on these bonds range from 5.375 percent to 6.375 percent. Because of interest rate swaps we entered into earlier in the year to offset the impact of a potential rise in interest rates, we paid $10.3 million to counterparties at the closing of these transactions.

In 2008, we expect to issue approximately $300 million of long-term debt to finance our capital program.

Our first mortgage bonds are rated A3, BBB+, and A- with a stable outlook by Moody’s Investors Service, Standard & Poor’s and Fitch Ratings, respectively. To ensure the consistency of these ratings, which aid in the achievement of competitive market rates for our debt issuances, we seek to maintain certain credit metrics satisfactory to the rating agencies, which include a target capitalization structure of approximately 55 percent debt and 45 percent equity. The three agencies each may include in the debt component of capitalization additional factors, such as the net present value of remaining operating leases and postretirement benefit obligations. Before the application of such adjustments, our ratio of consolidated total debt to total capitalization was approximately 53.2 percent as of December 31, 2007. We seek to maintain our target structure over the long term through a proper balance of ca pital infusions from NU parent and new debt issuances or borrowings.

In 2007 and 2006, NU contributed equity to us of $570.7 million and $60.8 million, respectively. In general, we pay approximately 60 percent of our cash earnings to NU in the form of common dividends. In 2007, we paid common dividends to NU of $79.2 million and $63.7 million, respectively.

The Federal Power Act limits the payment of dividends to our retained earnings balance. In addition, certain state statutes may impose additional limitations on us. We also have a revolving credit agreement that imposes a leverage restriction tied to our ratio of consolidated total debt to total capitalization.

Along with other NU subsidiaries, we are party to a $400 million credit facility which expires on November 6, 2010. We can borrow up to $200 million on a short-term basis, or subject to regulatory approvals, on a long-term basis. At December 31, 2007, we had no borrowings outstanding under this facility.

In addition to our revolving credit facility, we have an arrangement with a financial institution under which we can sell up to $100 million of our accounts receivable and unbilled revenues. There was $20 million sold under the facility at December 31, 2007. For more information regarding the sale of receivables, see Note 1K, "Summary of Significant Accounting Policies - Sale of Customer Receivables," to the consolidated financial statements.

Cash capital expenditures included on the accompanying consolidated statements of cash flows and described in the liquidity section of this management's discussion and analysis do not include amounts incurred but not paid, cost of removal, the allowance for funds used during construction (AFUDC) related to equity funds, and the capitalized portion of pension expense or income. Our cash capital expenditures totaled $826.2 million in 2007, compared with $567.2 million in 2006 and $444.4 million in 2005. The increase in our cash capital expenditures was primarily the result of higher transmission capital expenditures.

We project 2008 capital expenditures of approximately $872 million, compared to projected operating cash flows of approximately $380 million. As a result, we expect to issue the $300 million in long-term debt mentioned above and borrow on our credit facilities in 2008. We expect to fund the majority of our expected capital expenditures through 2012 with internally generated cash flows. Therefore, we expect to issue debt on a regular basis.

Impact of Credit Markets: As previously discussed, we plan to issue $300 million of long-term debt in 2008 and have entered into forward interest rate swaps to hedge exposure to market rates for these planned issuances. Due to the overall uncertainties in the market, however, the credit spreads on these issuances may be higher than we have experienced in the past. We believe that the credit markets will continue to be supportive of our debt issuances and that, despite volatility in treasury rates and credit spreads, we will be able to issue this debt at competitive rates.

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

Business Development and Capital Expenditures

Our consolidated capital expenditures including amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income, totaled $943.9 million in 2007, compared with $625.9 million in 2006 and $469.9 million in 2005.

We project a total of $3.5 billion in capital expenditures from 2008 through 2012, which also includes amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income (all of which are predominately non-cash factors in determining rate base). A summary of these estimated capital expenditures for our transmission segment and distribution segment for 2008 through 2012 is as follows (millions of dollars):

	Year					
	2008	**2009**	**2010**	**2011**	**2012**	**Totals**
Transmission	$ 538	$ 311	$ 155	$ 420	$ 530	$ 1,954
Distribution	334	291	289	298	297	1,509
Total	$ 872	$ 602	$ 444	$ 718	$ 827	$ 3,463

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

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

	Year				
	2008	**2009**	**2010**	**2011**	**2012**
Transmission	$ 1,763	$ 2,168	$ 2,199	$ 2,515	$ 2,828
Distribution	2,130	2,296	2,450	2,584	2,705
Total	$ 3,893	$ 4,464	$ 4,649	$ 5,099	$ 5,533

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

Transmission Segment: Our transmission rate base totaled approximately $1.2 billion at December 31, 2007, including approximately $290 million of incurred construction costs, or construction work in progress (CWIP), compared with approximately $800 million at December 31, 2006, including approximately $108 million of CWIP. In addition, the transmission segment recorded $345 million and $142 million of CWIP at December 31, 2007 and 2006, respectively, that were not in rate base. The projected transmission rate base amounts reflected above include CWIP for 50 percent of the southwest Connecticut projects (Middletown to Norwalk, Connecticut; Norwalk to Stamford, Connecticut; and Norwalk, Connecticut to Northport-Long Island, New York) and, assuming FERC will allow related CWIP in rate base, 100 percent of our portion of the New England East-West 345 kilovolt (KV) and 115 KV Overhead project referred to below. The CWIP amounts included in rate base for these projects are $233 million, $33 million, $96 million, $352 million, and $372 million, respectively, for the 2008 to 2012 periods.

Transmission segment capital expenditures were $660.6 million, $415.6 million, and $215.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

The increase in transmission segment capital expenditures in 2007 as compared with 2006 and 2005 primarily relates to a significant enhancement of our transmission system in southwest Connecticut. We completed one major transmission project, the 21-mile 115 KV/345 KV transmission project between Bethel, Connecticut and Norwalk, Connecticut, in 2006 and have three major projects currently under construction in southwest Connecticut, including:

- A 69-mile, 345 KV/115 KV transmission project from Middletown to Norwalk, Connecticut. Our portion of this project is estimated to cost approximately $1.05 billion. At December 31, 2007, our portion of this project was approximately 62 percent complete and at the end of February of 2008, was approximately 70 percent complete. As of December 31, 2007, we had capitalized $593 million associated with this project. Although the project is scheduled to be completed at the end of 2009, construction of the project is currently ahead of schedule, and we have reviewed the remaining work to determine whether it can be completed at an earlier date. As a result of this review, we now expect to complete this project in mid-2009. This early completion date would not have a significant impact on our earnings guidance.

- A two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), construction of which began in October of 2006. This project is estimated to cost approximately $223 million. This project is scheduled to be completed by the end of 2008. At December 31, 2007, this project was approximately 69 percent complete, and at the end of February of 2008, was approximately 74 percent complete. As of December 31, 2007, we had capitalized $133 million associated with this project.

- The replacement of the 138 KV 11-mile undersea electric transmission cable between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable). We and the Long Island Power Authority (LIPA) each own approximately 50 percent of the line. Our portion of the project is estimated to cost $72 million. After the final regulatory permits were received, marine construction activities commenced in October of 2007, and the project is expected to be placed in service in the second half of 2008. The pre-existing cables were decommissioned in September of 2007, and approximately 94 percent of the cables was removed as of December 31, 2007, including all portions located in Connecticut. Installation of the new cable began in early February of 2008. At December 31, 2007, the project was approximately 63 percent complete, and at the end of February of 2008, was approxi mately 72 percent complete. As of December 31, 2007, we had capitalized $45 million associated with this project, including the cost of the new cable, which was delivered in the fourth quarter of 2007.

In addition to our current transmission construction in southwest Connecticut, NU continues to work with ISO-NE to refine the design criteria of its next series of major transmission projects, including the New England East-West 345 KV and 115 KV Overhead project (NEEWS Overhead project). The NEEWS Overhead project includes three 345 KV transmission upgrades that will collectively address the region's transmission needs and better connect the major east-west transmission interfaces in Southern New England: 1) the Greater Springfield 345 KV Reliability Project, 2) the Central Connecticut Reliability Project, and 3) the Interstate Reliability Project. A fourth upgrade, National Grid's Rhode Island Reliability Project, is also included in the NEEWS Overhead project. In early 2007, NU entered into a formal agreement with National Grid to plan and permit these projects and expects the ISO-NE technical review process with r espect to the NEEWS Overhead project to conclude by mid- to late- 2008. NU will make the filing of the first project applications with the various state siting authorities shortly after receiving the technical approvals from ISO-NE. NU continues to work with ISO-NE to ensure that the design of these projects balances needs and reliability, operational flexibility, and cost. At this time, NU expects the siting process for the NEEWS Overhead project to be completed by 2010 and to complete construction in 2013. NU has not yet updated its detailed estimate of the total cost for the NEEWS Overhead project, and the timing of expenditures is highly dependent upon receipt of technical and siting approvals.

Assuming that virtually all of the 345 KV portions of the NEEWS Overhead project are constructed overhead and on existing rights of way, NU are maintaining its estimate of its share of the cost of the NEEWS Overhead project at approximately $1.05 billion, of which a significant portion will be incurred by us. However, as NU continues to review the designs of the NEEWS Overhead project with ISO-NE over the coming months, these figures are expected to change. NU anticipates having additional information on the scope and costs of these projects by mid-2008.

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

Distribution: Our distribution segment capital expenditures were $283.3 million, $210.3 million and $254.6 million in 2007, 2006 and 2005, respectively.

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

Transmission Rate Matters and FERC Regulatory Issues

Most New England utilities, including our company, generation owners and marketers are parties to a series of agreements that provide for coordinated planning and operation of the region's generation and transmission facilities and the market rules by which these parties participate in the wholesale markets and acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent from all market participants, has served as the Regional Transmission Operator

(RTO) for New England since February 1, 2005. ISO-NE works to ensure the reliability of the New England transmission system, administers the independent system operator tariff (ISO Tariff), subject to FERC approval, oversees the efficient and competitive functioning of the regional wholesale power market and determines which portion of the costs of our major transmission facilities are regionalized throughout New England.

Transmission - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of NU's wholesale transmission revenues, including ours, are collected under the ISO-NE FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Local Network Service (LNS) rate schedules to recover transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, including our transmission business, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, which NU administers, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local tra nsmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining three southwest Connecticut projects (Middletown-Norwalk, Glenbrook Cables and Long Island Replacement Cable). The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to retail customers. At December 31, 2007, the LNS rates for our transmission segment were in an underrecovery position of approximately $18 million, which will be recovered from LNS customers in mid-2008. We believe that these rates will provide us with timely reco very of transmission costs, including costs of our major transmission projects.

FERC ROE Decision: As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (FERC ROE decision), we recorded an estimated regulatory liability for refunds of $17.9 million as of December 31, 2006. In 2007, we completed the customer refunds that were calculated in accordance with the compliance filing required by the FERC ROE decision and refunded approximately $17 million to regional, local and localized transmission customers. The $0.9 million positive pre-tax difference ($0.5 million after-tax) between the estimated regulatory liability recorded and the actual amount refunded was recognized in earnings in 2007.

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

Our transmission segment refunded approximately $1.6 million of revenues and interest related to the July 26, 2007 order (approximately $1 million after-tax), which was recorded in 2007.

Legislative Matters

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

On December 28, 2007, the Connecticut Department of Environmental Protection (DEP) released draft RGGI regulations and conducted a public hearing on February 8, 2008. The DEP plans to have these rules finalized by May of 2008 and to participate in a proposed open regional auction of CO_2 allowances in June of 2008. The DEP has proposed an auction of 91 percent of allocated CO_2 allowances, with the remainder set aside for certain clean energy projects. The DEP has also proposed the first compliance period affecting facilities to begin on January 1, 2009. Although we currently do not have any facilities subject to the RGGI program, we expect the cost of purchased energy supply to increase due to RGGI requirements.

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

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

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

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

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

Regulatory Developments and Rate Matters

Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P and other NU companies, which recover these costs through rates charged to their retail customers. We have a retail transmission cost tracking mechanism as part of our rates. This tracking mechanism allows us to charge our retail customers for transmission charges on a timely basis.

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

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

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

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

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

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

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

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

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

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

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

Also pursuant to the Energy Independence Act, the DPUC conducted a request for proposal process and selected three generating projects to be built or modified that would be eligible to sign contracts for differences (CfDs) with us and UI for a total of approximately 782 MW of capacity. The process also selected one new demand response project for 5 MW. The CfDs obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets. The contracts are for periods of up to 15 years and are subject to another similar sharing agreement between us and UI. These contracts have been approved by the DPUC and signed by us or UI, whichever is the primary obligor. Our portion of the costs and benefits of these contracts will be paid by or refunded to our customers. Our costs under these agreements will depend on the capacity prices that th e projects receive in the ISO-NE capacity markets. For further information, see Note 3, "Derivative Instruments," to the consolidated financial statements.

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

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

Contingent Matters:

The item summarized below contains contingencies that may have an impact on our net income, financial position or cash flows. See Note 5A, "Commitments and Contingencies - Regulatory Developments and Rate Matters," to the consolidated financial statements for further information regarding these matters.

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

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

Deferred Contractual Obligations

We have significant decommissioning and plant closure cost obligations to the Yankee Companies, which have completed the physical decommissioning of all three of their facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including us. We recover these costs through DPUC-approved retail rates. We own 34.5 percent of CYAPC, 24.5 percent of YAEC, and 12 percent of MYAPC.

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

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

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

MYAPC: MYAPC is collecting revenues from us and other owners that are adequate to recover the remaining cost of decommissioning its plant, and we expect to recover our respective share of such costs through future rates.

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

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

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

Our aggregate share of these damages is $29 million. We cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, we do believe that any net settlement proceeds we receive would be incorporated into FERC-approved recoveries, which would be passed on to our customers through reduced charges.

Off-Balance Sheet Arrangements

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

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

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

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

Enterprise Risk Management

NU implemented an Enterprise Risk Management (ERM) methodology for identifying the principal risks to itself and its affiliates, including us. ERM involves the application of a well-defined, enterprise-wide methodology that will enable NU's Risk and Capital Committee, comprised of NU’s senior officers, to oversee the identification, management and reporting of the principal risks of our 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 NU’s Board of Trustees.

Critical Accounting Policies and Estimates

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

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

We account for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." We have established a regulatory asset for temporary differences recorded as deferred tax liabilities that will be recovered in rates in the future. The regulatory asset amounted to $279.4 million and $266.6 million at December 31, 2007 and 2006, respectively. Regulatory agencies in certain jurisdictions in which we operate require the tax effect of specific temporary differences to be "flowed through" to our customers. Flow through treatment means that deferred tax expense is not recorded on the consolidated statements of income. Instead, the tax effect of the temporary difference impacts both amounts for income tax expense currently included in customers' rates and our net income. Flow through treatment can result in effective income tax rates that are significantly different than expected income ta x rates.

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

Effective on January 1, 2007, we implemented Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." FIN 48 applies to all income tax positions reflected on our balance sheets that have been included in previous tax returns or are expected to be included in future tax returns. FIN 48 addresses the methodology to be used prospectively in recognizing, measuring and classifying the amounts associated with tax positions that are deemed to be uncertain, including related interest and penalties. As a result of implementing FIN 48, we recognized a cumulative effect of a change in accounting principle of $24 million as a reduction to the January 1, 2007 balance of retained earnings.

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

Derivative Accounting: Certain contracts for the purchase or sale of energy or energy related products are derivatives.

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

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

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

In 2007, we 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 our financial statements pursuant to EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." This guidance applies to initial fair values only, and not to subsequent changes in value. Subsequent changes in the values of these contracts were substantial, primarily due to reductions in the expected market prices of capacity. Accordingly, at December 31, 2007, we estimated and recorded on our balance sheet approximately $110 million of total n egative changes in fair value of the derivative contracts since inception. The initial estimated negative fair values of these contracts of approximately $100 million will be recorded as part of the effect on derivatives of implementing FAS 157 in the first quarter of 2008. The $110 million net change in contract value was recorded as a regulatory asset as the costs of the contracts are recoverable from our 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.

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

For further information, see Note 1E, "Summary of Significant Accounting Policies - Derivative Accounting," and Note 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 delivered to customers that has 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 2007.

We 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 ID, "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: Our accounting policies conform to GAAP 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."

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

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

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

  For more information, see Note 5A, "Commitments and Contingencies - Regulatory Developments and Rate Matters," to the accompanying consolidated financial statements.

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 we will recover the regulatory assets that have been recorded. If we determined that we could no longer apply SFAS No. 71 to our operations, or if we could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If we determine that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that we record the charge in earnings at that time.

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

Pension and PBOP: We participate in a uniform noncontributory defined benefit retirement plan (Pension Plan), sponsored by NU, covering substantially all our regular employees. In addition to the Pension Plan, we also participate in a Postretirement Benefits Other Than Pensions *(*PBOP Plan), sponsored by NU, to provide certain health care benefits, primarily medical and dental, and life insurance benefits to retired employees. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost is based on several significant assumptions. If these assumptions were changed, the

resulting changes in benefit obligations, fair values of plan assets, funded status and net periodic expense could have a material impact on our consolidated financial statements.

Pre-tax periodic pension expense for the Pension Plan was a benefit of $15.6 million in 2007, an expense of $2.4 million in 2006, and a benefit of $0.6 million for 2005. The pension benefit and 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 $16.1 million, $21.6 million and $21.5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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

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

The actual asset allocations at December 31, 2007 and 2006 approximated these target asset allocations. NU routinely reviews the actual asset allocations and periodically rebalances the investments to the targeted asset allocations when appropriate. For information regarding actual asset allocations, see Note 4A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements.

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

Actuarial Determination of Expense: NU bases the actuarial determination of Pension Plan and PBOP Plan expense on a market-related value of assets (MRVA), which reduces year-to-year volatility. This MRVA calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the MRVA and the actual return based on the fair value of assets. At December 31, 2007, total investment gains to be recognized in the MRVA over the next four years are gains of $49.7 million for the Pension Plan and losses of $0.9 million for the PBOP Plan. As these asset gains/losses are reflected in MRVA over the next four years, they will be subject to amortization with other unrecognized gains/losses. The Plans currently amortize unrecognized gains/losses as a componen t of pension and PBOP expense over approximately 12 years, which is the average future service lives of the employees at December 31, 2007. At December 31, 2007, the net actuarial loss subject to amortization over the next 12 years was $15.9 million and $43.9 million, respectively, which excludes $49.7 million of gains and $0.9 million of losses on previous investment amounts not currently reflected in the MRVA for the Pension Plan and PBOP Plan, respectively.

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

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

	Pension Plan		Postretirement Plan	
Year	Expected Contributions	Forecasted Income	Expected Contributions	Forecasted Expense
2008	$ -	$ 21.4	$ 15.7	$ 15.7
2009	$ -	$ 23.9	$ 14.5	$ 14.5
2010	$ -	$ 30.8	$ 13.3	$ 13.3

Future actual Pension and PBOP expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the plans and amounts capitalized. Beginning in 2007, we made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $1.1 million in 2007 and is estimated to be $1.8 million in 2008.

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

	At December 31,			
	Pension Plan Cost		Postretirement Plan Cost	
Assumption Change	2007	2006	2007	2006
Lower long-term rate of return	$ (5.1)	$ 4.8	$ 0.5	$ 0.5
Lower discount rate	$ (4.0)	$ 4.7	$ 0.4	$ 0.3
Lower compensation increase	$ 2.5	$ (2.5)	N/A	N/A

Plan Assets: The market-related value of the Pension Plan assets has increased by $40.7 million to $1.1 billion at December 31, 2007. The projected benefit obligation (PBO) for the Pension Plan decreased by $51 million to $809.5 million at December 31, 2007. These changes have increased the overfunded status of the Pension Plan on a PBO basis by $91.7 million to $334.8 million at December 31, 2007. The PBO includes expectations of future employee compensation increases. We have not made any employer contributions to the Pension Plan since 1991.

The accumulated benefit obligation (ABO) of the Pension Plan was approximately $421.1 million and $332.5 million less than Pension Plan assets at December 31, 2007 and 2006. The ABO is the obligation for employee service and compensation provided through December 31, 2007.

The value of PBOP Plan assets has increased by $5 million to $106.3 million at December 31, 2007. The benefit obligation for the PBOP Plan has decreased by $2.2 million to $184.9 million at December 31, 2007. These changes have decreased the underfunded status of the PBOP Plan on an accumulated projected benefit obligation basis from $85.8 million at December 31, 2006 to $78.6 million at December 31, 2007. We have made a contribution each year equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits.

Health Care Cost: The health care cost trend assumption used to project increases in medical costs was reset at 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 $0.4 million in 2007 and $0.5 million in 2006. Changes in the long-term health care cost trend assumption could have a material impact on our financial statements.

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

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

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

In 2007, the DPUC approved two of our contracts associated with the capacity of two generating projects to be built or modified and two capacity-related contracts entered into by UI, one with a generating project to be built and one with a new demand response project. The contracts, referred to as CfDs, obligate us and UI 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. We have an agreement with UI under which we will share the costs and benefits of these four CfDs with 80 percent to us and 20 percent to UI. The ultimate cost to us under the contracts will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. We determined that these contracts do not require consolidation.

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

Other Matters

Accounting Standards Issued But Not Yet Adopted:

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

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

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 is effective in the first quarter of 2008, with the effect of application to eligible items as of January 1, 2008 required to be reflected as a cumulative-effect adjustment to the opening balance of retained earnings. If a company elects the fair value option for an eligible item, changes in that item's fair value at subsequent reporting dates must be recognized in earnings. We are currently evaluating whether or not to elect the fair value option for our securities held in trust as of January 1, 2008. Implementation of SFAS No. 159 for our securities held in trust is not expected to have a material effect on the consolidated financial statements.

Contractual Obligations and Commercial Commitments:

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

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Totals
Long-term debt maturities [a] [b]	$ -	$ -	$ -	$ -	$ -	$ 1,793.7	$ 1,793.7
Estimated interest payments on existing debt [c]	104.3	104.3	104.3	104.3	104.3	1,613.2	2,134.7
Capital leases [d] [e]	3.2	3.5	1.7	1.7	1.8	16.8	28.7
Operating leases [e] [f]	18.8	17.2	15.3	12.0	10.2	45.0	118.5
Required funding of other post-retirement benefit obligations [f]	15.7	14.5	13.3	12.7	12.1	N/A	68.3
Estimated future annual costs [e] [g]	783.3	278.3	307.1	532.3	531.7	1,753.4	4,186.1
Other purchase commitments [f] [h]	450.9	-	-	-	-	-	450.9
Totals [i]	$ 1,376.2	$ 417.8	$ 441.7	$ 663.0	$ 660.1	$ 5,222.1	$ 8,780.9

(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 disclosed above excludes $238.7 million of fees and interest due for spent nuclear fuel disposal costs and a negative $3.9 million of net unamortized premium and discount as of December 31, 2007.

(c) Estimated interest payments on fixed-rate debt are calculated by multiplying the coupon rate on the debt by its scheduled notional amount outstanding for the period of measurement.

(d) The capital lease obligations include imputed interest of $15.1 million as of December 31, 2007.

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

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

(g) Other than the mark-to-market on respective derivative contracts, these obligations are not included on our consolidated balance sheets. Estimated costs for 2008 are higher than costs in future years due to the timing of completion of transmission segment development projects. For further information on these estimated future annual costs, see Note 5D, “Commitments and Contingencies – Long-Term Contractual Arrangements.”

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

(i) Excludes FIN 48 unrecognized tax benefits of $75.9 million as of December 31, 2007 as we cannot make reasonably reliable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities.

Rate reduction bond amounts are non-recourse to us, have no required payments over the next five years and are not included in this table. Our standard offer service contracts and default service contracts also are not included in this table. The estimated payments under interest rate swap agreements are not included in this table as the estimated payment amounts are not determinable. In addition, there are no Pension Plan contributions expected and therefore no amounts are included in this table. For further information regarding our contractual obligations and commercial commitments, see Note 2, "Short-Term Debt," Note 4A, “Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pensions,” Note 5D, "Commitments and Contingencies - Long-Term Contractual Arrangements," Note 7, "Leases," and Note 11, "Long-Term Debt," to the consolidated f inancial statements.

Forward Looking Statements: This discussion and analysis includes statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, financial performance or growth and other statements that are not historical facts. These statements are "forward looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify these "forward looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and similar expressions. Forward looking statements involve risks and uncertainties that may cause actual results or outcomes to differ materially from those included in the forward looking statemen ts. Factors that may cause actual results to differ materially from those included in the forward looking statements include, but are not limited to, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels or timing of capital expenditures, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, 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.cl-p.com.

RESULTS OF OPERATIONS

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

Income Statement Variances	2007 over/(under) 2006		2006 over/(under) 2005	
(Millions of Dollars)	Amount	Percent	Amount	Percent
Operating Revenues	$ (298)	(7) %	$ 513	15 %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(327)	(13)	458	21
Other operation	(79)	(13)	57	10
Maintenance	7	6	6	7
Depreciation	4	3	14	11
Amortization of regulatory assets/(liabilities), net	32	(a)	(71)	(a)
Amortization of rate reduction bonds	9	7	9	7
Taxes other than income taxes	7	4	6	4
Total operating expenses	(347)	(9)	479	15
Operating Income	49	21	34	17
Interest expense, net	21	17	(2)	(2)
Other income, net	2	5	(7)	(16)
Income before income tax expense	30	19	29	23
Income tax expense	96	(a)	(76)	(a)
Net income	$ (66)	(33) %	$ 105	(a) %

(a) Percent greater than 100.

Comparison of the Year 2007 to the Year 2006

Operating Revenues
Operating revenues decreased $298 million due to lower distribution segment revenues ($373 million), partially offset by higher transmission segment revenues ($75 million).

The distribution segment revenue decrease of $373 million is primarily due to the components of revenues, which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($388 million). The distribution segment revenue tracking components decreased $388 million primarily due to a decrease in revenues associated with the recovery of generation service and related congestion charges ($265 million) and lower delivery-related FMCC revenue ($104 million). The lower generation service and related congestion charge revenue was primarily due to a reduction in load caused primarily by customer migration to third party suppliers, partially offset by an increase in these rate components to recover higher 2007 supply prices. The lower delivery-related FMCC revenue was primarily due to a decrease in this rate component in 2007 as a result of the use of prior year over reco veries to recover current year costs, as well as lower anticipated RMR costs in 2007. 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 revenues which impacts earnings increased $14 million as a result of the rate increase effective January 1, 2007 and higher retail sales. Retail sales increased 1.7 percent in 2007 compared to the same period in 2006.

Transmission segment revenues increased $75 million primarily due to a higher rate base and higher operating expenses, which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power expense decreased $327 million primarily due to a decrease in generation service supply costs ($286 million) and lower other purchased power costs ($73 million), partially offset by an increase in deferred fuel costs of $32 million, all of which are included in regulatory commission-approved tracking mechanisms. The $286 million decrease in supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers, partially offset by higher 2007 supply prices. These supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply Standard Service and Last Resort Service load through a competitive solicitation process. The $32 million increase in deferred fuel costs was largely the result of the deferral of significant refunds received from the ISO-NE associated with previously re mitted reliability must run payments that must be returned to customers.

Other Operation
Other operation expenses decreased $79 million primarily due to lower RMR costs ($133 million), which are tracked and recovered through the FMCC, partially offset by higher Energy Independence Act (EIA) expenses which will also be recovered through the FMCC deferral mechanism ($29 million), Summer Saver Rewards Program which was implemented in 2007 as a result of a legislative act ($14 million) and higher administrative expense ($8 million).

Maintenance
Maintenance expenses increased $7 million primarily due to higher transmission segment expenses ($5 million) and higher distribution segment expenses ($2 million).

Higher transmission segment expenses of $5 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 distribution segment expenses of $2 million in 2007 are primarily due to higher expenses related to substation maintenance, underground network inspection activities, line transformer maintenance, partially offset by lower expenses related to overhead lines maintenance primarily due to less storm-related expenses.

Depreciation
Depreciation expense increased $4 million primarily due to higher utility plant balances resulting from the ongoing construction program.

Amortization of Regulatory Assets/(Liabilities), Net
Amortization of regulatory assets/(liabilities), net increased $32 million primarily due to higher amortization related to the recovery of transition charges ($32 million), higher SFAS No. 109 amortization ($7 million), partially offset by a lower system benefit charge deferral ($8 million).

Amortization of Rate Reduction Bonds
Amortization of rate reduction bonds increased $9 million. The higher portion of principal within the rate reduction bonds' payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $7 million primarily due to higher property taxes primarily related to new transmission projects such as the Bethel-Norwalk project that were completed in 2006, but not reflected in our tax assessment until 2007.

Interest Expense, Net
Interest expense, net increased $21 million primarily due to higher interest on long-term debt ($19 million) mainly as a result of $250 million of new debt issued in June of 2006, $300 million of new debt issued in March of 2007 and $200 million of new debt issued in September of 2007, higher FMCC deferral interest ($6 million) and higher interest on short-term debt ($2 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($9 million).

Other Income, Net
Other income, net increased $2 million primarily due to a higher equity AFUDC income ($7 million) as a result of higher eligible construction work in progress due to the transmission construction program, higher Energy Independence Act (EIA) incentives ($4 million) and higher equity of earnings of regional nuclear generating companies ($3 million), partially offset by the elimination of the TSO procurement fee approved by the DPUC associated with the TSO supply procurement that expired at the end of 2006 ($11 million).

Income Tax Expense/(Benefit)
Income tax expense/(benefit) increased $96 million primarily due to the nonrecurring tax items in 2006 which included a $74 million tax benefit from the removal of deferred tax balances associated with a PLR received from the IRS, a decrease in favorable tax adjustments, lower state tax credits and higher pre-tax earnings.

Comparison of the Year 2006 to the Year 2005

Operating Revenues
Operating revenues increased $513 million due to higher distribution segment revenues ($471 million) and higher transmission segment revenues ($42 million).

The distribution segment revenue increase of $471 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($472 million). The distribution segment revenue tracking components increased $472 million primarily due to higher TSO related revenues ($458 million) as a result of the pass through of higher energy supply costs, an increase in revenues associated with the recovery of FMCC charges ($36 million) and higher retail transmission revenues ($24 million), partially offset by lower wholesale revenues ($45 million), as a result of the expiration or sale of market-based contracts. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods.

The distribution component of revenues which impacts earnings was flat, with an increase in rates offset by lower sales. Retail sales decreased 4.9 percent in 2006 compared to the same period of 2005.

Transmission segment revenues increased $42 million primarily due to a higher rate base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power expense increased $458 million primarily due to higher standard offer supply costs and higher purchased power costs as a result of higher energy prices, which are included in regulatory commission approved tracking mechanisms, partially offset by lower fuel costs for wholesale transactions.

Other Operation
Other operation expenses increased $57 million primarily due to higher reliability must run (RMR) costs ($36 million) which are tracked and recovered through the FMCC, higher other power pool related costs ($7 million), higher conservation and load management (C&LM) expenses ($7 million) which are included in a regulatory rate tracking mechanism, and higher uncollectible account expenses ($5 million).

Maintenance
Maintenance expenses increased $6 million primarily due to higher tree trimming expenses ($3 million), higher expenses related to overhead lines ($1 million) and underground lines ($1 million), and higher station equipment expenses ($1 million).

Depreciation
Depreciation expense increased $14 million primarily due to higher utility plant balances resulting from the ongoing construction program.

Amortization of Regulatory Assets/(Liabilities), Net
Amortization of regulatory assets/(liabilities), net decreased $71 million primarily due to lower amortization related to the recovery of transition charges ($70 million).

Amortization of Rate Reduction Bonds
Amortization of rate reduction bonds increased $9 million. The higher portion of principal within the rate reduction bonds' payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $6 million primarily due to higher gross earnings taxes ($5 million) and higher property taxes ($2 million).

Interest Expense, Net
Interest expense, net decreased $2 million primarily due to lower rate reduction bond interest resulting from lower principal balances outstanding, partially offset by higher interest on long-term debt mainly as a result of $250 million of new debt issued in June of 2006 and $200 million of new debt issued in April of 2005.

Other Income, Net
Other income, net decreased $7 million primarily due to a lower TSO procurement fee ($7 million) and lower equity AFUDC income resulting from the partial inclusion of transmission CWIP in rate base ($4 million), partially offset by Energy Independence Act (EIA) incentives ($5 million).

Income Tax Benefit/(Benefit)
Income tax expense/(benefit) decreased $76 million in 2006 due to favorable tax adjustments, partially offset by higher equity pre-tax earnings. Deferred tax adjustments included a tax benefit of $74 million to remove the UITC and EDIT deferred tax balances in conformity with an IRS PLR and pursuant to a DPUC order. Additional tax benefits resulted from higher state tax credits, a deferred tax adjustment related to generation plant sold to an affiliate, a Connecticut tax settlement and year over year change in estimate to actual adjustments. These additional benefits were partially offset by less favorable plant related differences.

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 The Connecticut Light and Power Company and subsidiaries (CL&P or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, CL&P conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that our internal controls over financial reporting were effective as of December 31, 2007.

February 28, 2008

Report of Independent Registered Public Accounting Firm

To the Board of Directors of
The Connecticut Light and Power Company:

We have audited the accompanying consolidated balance sheets of The Connecticut Light and Power Company and subsidiaries (a Connecticut corporation and a wholly owned subsidiary of Northeast Utilities) (the "Company") as of December 31, 2007 and 2006, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of The Connecticut Light and Power Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1.G., the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, as of January 1, 2007.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
February 28, 2008

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

At December 31,	2007	2006
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 538	$ 3,310
Investments in securitizable assets	308,182	375,656
Receivables, less provision for uncollectible accounts of $7,874 in 2007 and $1,679 in 2006	118,342	73,052
Accounts receivable from affiliated companies	3,339	1,965
Unbilled revenues	8,225	8,044
Taxes receivable	16,245	-
Materials and supplies	55,477	39,447
Derivative assets - current	57,003	45,031
Prepayments and other	17,387	15,945
	584,738	562,450
Property, Plant and Equipment:		
Electric utility	4,899,075	4,557,231
Less: Accumulated depreciation	1,279,697	1,260,526
	3,619,378	3,296,705
Construction work in progress	782,468	337,665
	4,401,846	3,634,370
Deferred Debits and Other Assets:		
Regulatory assets	1,329,963	1,477,375
Prepaid pension	334,786	243,139
Derivative assets - long-term	278,726	249,423
Other	88,040	154,537
	2,031,515	2,124,474
Total Assets	$ 7,018,099	$ 6,321,294

The accompanying notes are an integral part of these consolidated financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

At December 31,	2007	2006
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to affiliated companies	$ 38,825	$ 258,925
Accounts payable	368,356	326,163
Accounts payable to affiliated companies	53,096	47,906
Accrued taxes	-	186,647
Accrued interest	29,532	29,587
Derivative liabilities - current	4,234	4,101
Other	107,940	80,543
	601,983	933,872
Rate Reduction Bonds	548,686	743,899
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	698,789	719,470
Accumulated deferred investment tax credits	21,412	24,019
Deferred contractual obligations	152,735	185,195
Regulatory liabilities	601,455	582,841
Derivative liabilities - long-term	135,991	31,923
Accrued postretirement benefits	78,587	85,768
Other	191,464	127,638
	1,880,433	1,756,854
Capitalization:		
Long-Term Debt	2,028,546	1,519,440
Preferred Stock - Non-Redeemable	116,200	116,200
Common Stockholder's Equity:		
Common stock, $10 par value - authorized 24,500,000 shares; 6,035,205 shares outstanding in 2007 and 2006	60,352	60,352
Capital surplus, paid in	1,243,940	672,693
Retained earnings	538,138	513,344
Accumulated other comprehensive (loss)/income	(179)	4,640
Common Stockholder's Equity	1,842,251	1,251,029
Total Capitalization	3,986,997	2,886,669
Commitments and Contingencies (Note 5)		
.		
Total Liabilities and Capitalization	$ 7,018,099	$ 6,321,294

The accompanying notes are an integral part of these consolidated financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2007	2006	2005
		(Thousands of Dollars)	
Operating Revenues	$ 3,681,817	$ 3,979,811	$ 3,466,420
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	2,277,054	2,603,882	2,145,834
Other	535,750	614,372	557,587
Maintenance	108,001	101,443	95,076
Depreciation	152,005	147,460	133,135
Amortization of regulatory assets/(liabilities), net	20,593	(11,251)	59,632
Amortization of rate reduction bonds	135,929	126,909	118,488
Taxes other than income taxes	167,943	160,926	154,619
Total operating expenses	3,397,275	3,743,741	3,264,371
Operating Income	284,542	236,070	202,049
Interest Expense:			
Interest on long-term debt	84,292	64,873	59,019
Interest on rate reduction bonds	37,728	46,692	55,796
Other interest	16,413	6,281	5,220
Interest expense, net	138,433	117,846	120,035
Other Income, Net	39,808	37,822	45,005
Income Before Income Tax Expense/(Benefit)	185,917	156,046	127,019
Income Tax Expense/(Benefit)	52,353	(43,961)	32,174
Net Income	$ 133,564	$ 200,007	$ 94,845
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME			
Net Income	$ 133,564	$ 200,007	$ 94,845
Other comprehensive (loss)/income, net of tax:			
Qualified cash flow hedging instruments	(4,814)	4,537	-
Unrealized (losses)/gains on securities	(5)	17	(22)
Minimum SERP liability	-	364	120
Other comprehensive (loss)/income, net of tax	(4,819)	4,918	98
Comprehensive Income	$ 128,745	$ 204,925	$ 94,943

The accompanying notes are an integral part of these consolidated financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock		Capital Surplus Paid In	Retained Earnings	Accumulated Other Comprehensive (Loss)/Income	Total
	Shares	Amount				
	(Thousands of Dollars, except share information)					
Balance at January 1, 2005	6,035,205	$ 60,352	$ 415,140	$ 347,176	$ (376)	$ 822,292
Net income for 2005				94,845		94,845
Dividends on preferred stock				(5,559)		(5,559)
Dividends on common stock				(53,834)		(53,834)
Allocation of benefits - ESOP			(476)			(476)
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			171			171
Capital stock expenses, net			186			186
Capital contribution from NU parent			197,794			197,794
Other comprehensive income					98	98
Balance at December 31, 2005	6,035,205	60,352	612,815	382,628	(278)	1,055,517
Net income for 2006				200,007		200,007
Dividends on preferred stock				(5,559)		(5,559)
Dividends on common stock				(63,732)		(63,732)
Allocation of benefits - ESOP			(157)			(157)
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			(995)			(995)
Capital stock expenses, net			275			275
Capital contribution from NU parent			60,755			60,755
Other comprehensive income					4,918	4,918
Balance at December 31, 2006	6,035,205	60,352	672,693	513,344	4,640	1,251,029
Adoption of FIN48 - accounting for uncertainty of income taxes				(24,030)		(24,030)
Net income for 2007				133,564		133,564
Dividends on preferred stock				(5,559)		(5,559)
Dividends on common stock				(79,181)		(79,181)
Allocation of benefits - ESOP			446			446
Capital stock expenses, net			140			140
Capital contribution from NU parent			570,661			570,661
Other comprehensive loss					(4,819)	(4,819)
Balance at December 31, 2007	6,035,205	$ 60,352	$1,243,940	$ 538,138	$ (179)	$ 1,842,251

The accompanying notes are an integral part of these consolidated financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2007	2006	2005
		(Thousands of Dollars)	
Operating Activities:			
Net income	$ 133,564	$ 200,007	$ 94,845
Adjustments to reconcile to net cash flows provided by operating activities:			
Bad debt expense	18,121	13,582	12,834
Depreciation	152,005	147,460	133,135
Deferred income taxes	28,725	(154,260)	(16,585)
Amortization of regulatory assets/(liabilities), net	20,593	(11,251)	59,632
Amortization of rate reduction bonds	135,929	126,909	118,488
Amortization of recoverable energy costs	3,440	3,839	36,090
Pension (income)/expense, net of capitalized portion	(8,271)	438	1,491
Regulatory overrecoveries/(refunds)	4,441	(80,888)	(73,442)
Deferred contractual obligations	(28,019)	(61,273)	(60,444)
Other non-cash adjustments	(17,930)	(7,223)	(8,730)
Other sources of cash	89	15,728	702
Other uses of cash	(13,436)	(804)	(14,192)
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(44,025)	22,924	25,648
Materials and supplies	(16,030)	(6,518)	284
Investments in securitizable assets	33,531	(158,254)	(113,410)
Other current assets	(3,208)	6,786	(1,779)
Accounts payable	3,457	56,628	25,312
Taxes (receivable)/accrued	(216,714)	126,116	61,297
Other current liabilities	13,471	11,421	16,097
Net cash flows provided by operating activities	199,733	251,367	297,273
Investing Activities:			
Investments in property and plant	(826,248)	(567,151)	(444,384)
Proceeds from sales of investment securities	2,015	2,210	1,883
Purchases of investment securities	(2,154)	(2,369)	(1,993)
Net proceeds from sale of property	-	-	21,993
Rate reduction bond escrow and other deposits	56,872	(51,985)	(5,048)
Other investing activities	3,923	12,032	6,126
Net cash flows used in investing activities	(765,592)	(607,263)	(421,423)
Financing Activities:			
Issuance of long-term debt	500,000	250,000	200,000
Retirement of rate reduction bonds	(195,213)	(112,580)	(138,754)
(Decrease)/increase in NU Money Pool borrowings	(220,100)	232,100	(63,200)
Capital contributions from NU parent	570,661	60,756	197,794
Decrease in short-term debt	-	-	(15,000)
Cash dividends on preferred stock	(5,559)	(5,559)	(5,559)
Cash dividends on common stock	(79,181)	(63,732)	(53,834)
Other financing activities	(7,521)	(4,080)	(604)
Net cash flows provided by financing activities	563,087	356,905	120,843
Net (decrease)/increase in cash	(2,772)	1,009	(3,307)
Cash - beginning of year	3,310	2,301	5,608
Cash - end of year	$ 538	$ 3,310	$ 2,301
Supplemental Cash Flow Information:			
Cash paid/(received) during the year for:			
Interest, net of amounts capitalized	$ 156,445	$ 117,856	$ 125,249
Income taxes	$ 241,219	$ (16,364)	$ (12,761)
Non-cash investing activities:			
Capital expenditures incurred but not paid	$ 126,148	$ 76,248	$ 53,725

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 The Connecticut Light and Power Company

The Connecticut Light and Power Company (CL&P or the company) is a wholly-owned subsidiary of Northeast Utilities (NU). CL&P is a reporting company under the Securities Exchange Act of 1934. 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 CL&P, 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. CL&P is subject to further regulation for rates, accounting and other matters by the FERC and the Connecticut Department of Public Utility C ontrol (DPUC). CL&P furnishes franchised retail electric service in Connecticut. CL&P's results include the operations of its distribution and transmission segments.

Several wholly-owned subsidiaries of NU provide support services for NU's companies, including CL&P. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. Three other subsidiaries construct, acquire or lease some of the property and facilities used by CL&P.

At December 31, 2007 and 2006, CL&P had a long-term receivable from NUSCO in the amount of $25 million that is included in deferred debits and other assets - other on the accompanying consolidated balance sheets related to the funding of investments held in trust by NUSCO in connection with certain postretirement benefits for CL&P employees.

Included in the consolidated balance sheet at December 31, 2007, are accounts receivable from affiliated companies and accounts payable to affiliated companies totaling $3.3 million and $53.1 million, respectively, relating to transactions between CL&P and other subsidiaries that are wholly-owned by NU. At December 31, 2006, these amounts totaled $2 million and $47.9 million, respectively.

Total CL&P purchases from Select Energy, Inc. (Select Energy), another NU subsidiary, were $6.1 million and $53.4 million for the years ended December 31, 2006 and 2005, respectively. There were no such purchases in 2007.

The Rocky River Realty Company (RRR), a subsidiary of NU, conveyed a Conservation Easement (CE) on a parcel of land to the Connecticut Forest and Park Association in 2007, as a mitigation requirement for CL&P's Middletown to Norwalk, Connecticut transmission project. Pursuant to this transaction, CL&P paid $1.4 million for the fair value of the land to RRR and RRR maintains ownership of the land. This payment has been recorded as a permitting cost for the Middletown to Norwalk project and is included as construction work in progress (CWIP) on the accompanying consolidated balance sheet as of December 31, 2007.

In 2007, CL&P made a discretionary contribution of $0.6 million to the NU Foundation, Inc. (Foundation), an independent not-for-profit charitable entity designed to invest in projects that emphasize economic development, workforce training and education, and a clean and healthy environment. The board of directors of the Foundation consists of certain NU officers. Any donations made to the Foundation negatively impact the earnings of CL&P.

B. Presentation

The consolidated financial statements of CL&P include the accounts of its subsidiaries, CL&P Receivables Corporation (CRC) and CL&P Funding LLC. 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.

C. Accounting Standards Issued But Not Yet Adopted

Fair Value Measurements: On September 15, 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is applicable to fair value measurements of derivative contracts that are subject to mark-to-market accounting and to other assets and liabilities that are reported at fair value or subject to fair value measurements.

Management is currently evaluating the effects of implementing SFAS No. 157, which are only expected to impact the consolidated balance sheet. These effects will include adjustments to reflect the initial fair value of derivative contracts that were in a gain or loss position at inception that was not recognized under previous accounting standards. SFAS No. 157 requires these adjustments to be recorded in retained earnings as of January 1, 2008. However, the cost or benefit of the contracts is expected to be fully recovered from or refunded to its customers. Therefore, adjustments to reflect these previously unrecorded balances will be recorded as regulatory assets or liabilities. In addition, updates to the fair values of previously recorded derivatives to reflect their exit prices and nonperformance risk will also be recorded as regulatory assets or liabilities.

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 is effective in the first quarter of 2008, with the effect of application to eligible items as of January 1, 2008 required to be reflected as a cumulative-effect adjustment to the opening balance of retained earnings. If a company elects the fair value option for an eligible item, changes in that item's fair value at subsequent reporting dates must be recognized in earnings. Management is currently evaluating whether or not to elect the fair value option for CL&P's securities held in trust as o f January 1, 2008. Implementation of SFAS No. 159 for CL&P's securities held in trust is not expected to have a material effect on the consolidated financial statements.

D. Revenues

CL&P's retail revenues are based on rates approved by the DPUC. In general, rates can only be changed through formal proceedings with the DPUC. However, CL&P utilizes DPUC-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.

Unbilled Revenues: Unbilled revenues represent an estimate of electricity delivered to customers for which 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 or under other circumstances.

CL&P estimates 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.

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, including CL&P's, are collected under the New England Independent System Operator (ISO-NE) FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Local Network Service (LNS) rate schedules to recover transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, administered by NU, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining three southwest Connecticut projects (Middletown-Norwalk, Glenbrook Cables and Long Island Replacement Cable). The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to retail customers. At December 31, 2007, the LNS rates for CL&P's transmission segment were in an underrecovery position of approximately $18 million, which will be recovered from LNS customers in mid-2008. CL&P believes that these rates will provide it with timely recovery of transmission costs, including costs of its major transmission projects.

Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P and other NU companies, which recover these costs through the rates charged to their retail customers. CL&P has a retail transmission cost tracking mechanism as part of its rates. This tracking mechanism allows CL&P to charge its retail customers for transmission charges on a timely basis.

E. Derivative Accounting

The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative. Non-derivative contracts are recorded at the time of delivery or settlement.

The application of derivative accounting under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, is complex and requires management judgment in the following respects: election and designation of the normal purchases and sales exception, identification of derivatives and embedded derivatives, identifying hedge relationships, assessing and measuring hedge ineffectiveness, and determining the fair value of derivatives. All of these judgments, depending upon their timing and effect, could have a significant impact on CL&P's 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 judgment applied in the election of the normal purchases and sales exception (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting is terminated and fair value accounting is applied.

Contracts that are hedging an underlying transaction and that qualify as derivatives that hedge exposure to the variable cash flows of a forecasted transaction (cash flow hedges) are recorded on the consolidated balance sheets at fair value with changes in fair value reflected in accumulated other comprehensive income. Cash flow hedges include forward interest rate swap agreements on proposed debt issuances. When a cash flow hedge is settled, the settlement amount is recorded in accumulated other comprehensive income and is amortized into earnings over the term of the debt. In addition, cash flow hedges impact earnings when hedge ineffectiveness is measured and recorded or when the forecasted transaction being hedged is no longer probable of occurring.

Emerging Issues Task Force (EITF) Issue No. 02-3, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities,” prohibits recording the initial gains and losses on derivative contracts if their estimated fair values are based on significant non-observable inputs. Based upon the significance of non-observable capacity prices to their valuation, the estimated initial fair values of CL&P’s contracts for differences (CfDs) are not recorded on the balance sheet as of December 31, 2007.

For further information regarding CL&P's derivative contracts, and their accounting, see Note 3, "Derivative Instruments," to the consolidated financial statements.

F. Regulatory Accounting

The accounting policies of CL&P 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 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 CL&P will recover its investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning an equity return, except for securitized regulatory assets and the majority of deferred benefit costs, which are not supported by equity. Amortization and deferrals of regulatory assets/(liabilities) are included on a net basis in amortization expense on the accompanying consolidated statements of income.

Regulatory Assets: The components of regulatory assets are as follows:

	At December 31,	
(Millions of Dollars)	**2007**	**2006**
Securitized assets	$ 548.2	$ 707.2
Income taxes, net	279.4	266.6
Unrecovered contractual obligations	148.0	163.7
Regulatory assets offsetting derivative liabilities	119.8	36.0
CTA and SBC undercollections	90.6	100.5
Deferred benefit costs	72.2	155.8
Other regulatory assets	71.8	47.6
Totals	$ 1,330.0	$ 1,477.4

Additionally, CL&P had $11.9 million and $11.1 million of regulatory costs at December 31, 2007 and 2006, respectively, that were included in deferred debits and other assets - other on the accompanying consolidated balance sheets. These amounts represent regulatory costs that have not yet been approved for recovery by the DPUC. Management believes these costs are recoverable in future cost-of-service, regulated rates.

Securitized Assets: In March of 2001, CL&P issued $1.4 billion in rate reduction certificates. CL&P used $1.1 billion of the proceeds from that issuance to buyout or buydown certain contracts with independent power producers (IPP). The unamortized CL&P securitized asset balance was $468.6 million and $604.5 million at December 31, 2007 and 2006, respectively. CL&P used the remaining proceeds from the issuance of the rate reduction certificates to securitize a portion of its SFAS No. 109, "Accounting for Income Taxes," regulatory asset. The securitized SFAS No. 109 regulatory asset had an unamortized balance of $79.6 million and $102.7 million at December 31, 2007 and 2006, respectively.

Securitized regulatory assets, which are not earning an equity return, are being recovered over the amortization period of their associated rate reduction certificates. All outstanding CL&P rate reduction certificates are scheduled to fully amortize by December 30, 2010.

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 DPUC, SFAS No. 109 and FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." Differences in income taxes between SFAS No. 109, FIN 48 and the rate-making treatment of the DPUC are recorded as regulatory assets which totaled $279.4 million and $266.6 million at December 31, 2007 and 2006, respectively. For further information regarding income taxes, see Note 1G, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial sta tements.

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 is responsible for its proportionate share of the remaining costs of the units, including decommissioning. A portion of these amounts, $148 million and $163.7 million at December 31, 2007 and 2006, respectively, were recorded as unrecovered contractual obligations regulatory assets. A portion of these obligations was securitized in 2001 and was included in securitized regulatory assets.

Regulatory Assets Offsetting Derivative Liabilities: The regulatory assets offsetting derivative liabilities relate to the fair value of contracts used to purchase power and other related contracts that will be collected from customers in the future. These amounts totaled $119.8 million and $36 million at December 31, 2007 and 2006, respectively. See Note 3, "Derivative Instruments," for further information. This asset is excluded from rate base.

CTA and SBC Undercollections: The Competitive Transition Assessment (CTA) allows CL&P to recover stranded costs, such as securitization costs associated with the rate reduction bonds, amortization of regulatory assets, and IPP over market costs. The System Benefits Charge (SBC) allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes and displaced workers protection costs. At December 31, 2007 and 2006, CTA undercollections totaled $54 million and $75.5 million, respectively. At December 31, 2007 and 2006, SBC undercollections totaled $36.6 million and $25 million, respectively.

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, Supplemental Executive Retirement 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 CL&P is a cost-of-service, rate regulated entity under SFAS No. 71, offsets were recorded as a regulatory asset of $72.2 million at December 31, 2007 and $155.8 million at December 31, 2006 as these amounts have been and continue to be recoverable in cost-of-service, regulated rates. Regulatory accounting was also applied to the portions o f the NUSCO costs that support CL&P, as these amounts are also recoverable. The deferred benefit costs are not in rate base.

Other Regulatory Assets: Included in other regulatory assets are the regulatory assets associated with the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $22.2 million and $25.8 million at December 31, 2007 and 2006, respectively. Management believes that recovery of these regulatory assets is probable.

At December 31, 2007 and 2006, other regulatory assets also include $15.4 million and $17.1 million, respectively, related to losses on reacquired debt, $10.4 million for the year ended December 31, 2007 related to the write-off of uncollectible hardship receivables and $23.8 million and $4.7 million, respectively, related to various other items.

Regulatory Liabilities: The components of regulatory liabilities are as follows:

	At December 31,	
(Millions of Dollars)	**2007**	**2006**
Regulatory liabilities offsetting derivative assets	$ 313.0	$ 294.5
GSC and FMCC overcollections	119.2	108.2
Cost of removal	116.6	134.4
Other regulatory liabilities	52.7	45.7
Totals	$ 601.5	$ 582.8

Regulatory Liabilities Offsetting 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 customers in the future. These amounts totaled $313 million and $294.5 million at December 31, 2007 and 2006, respectively. See Note 3, "Derivative Instruments," for further information. This liability is excluded from rate base.

GSC and FMCC Overcollections: The Generation Service Charge (GSC) allows CL&P to recover the costs of the procurement of energy for standard service, which includes forward capacity market charges. The Federally Mandated Congestion Charges (FMCC) mechanism allows CL&P to recover the costs of power market rules by the FERC, including Reliability Must Run costs. At December 31, 2007 and 2006, GSC and FMCC overcollections totaled $119.2 million and $108.2 million, respectively.

Cost of Removal: CL&P currently recovers amounts in rates for future costs of removal of plant assets. These amounts, which totaled $116.6 million and $134.4 million at December 31, 2007 and 2006, respectively, are classified as regulatory liabilities on the accompanying consolidated balance sheets. This liability is included in rate base.

Other Regulatory Liabilities: Other regulatory liabilities included a $17.9 million liability at December 31, 2006 related to transmission refunds to be provided to customers as a result of the FERC ROE decision, $21.4 million and $6.6 million for the years ended December 31, 2007 and 2006, respectively, related to a 50 percent reserve for allowance for funds used during construction (AFUDC) currently recovered in rate base as a result of FERC approved transmission incentives, and $31.3 million and $21.2 million related to various other items at December 31, 2007 and 2006, respectively.

G. Income Taxes

The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the DPUC, SFAS No. 109 and FIN 48. Details of income tax expense/(benefit) are as follows:

	For the Years Ended December 31,		
	2007	2006	2005
	(Millions of Dollars)		
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	$ 36.3	$ 104.9	$ 44.7
State	(10.0)	3.8	4.1
Total current	26.3	108.7	48.8
Deferred income taxes, net:			
Federal	23.5	(69.2)	(1.8)
State	5.2	(21.5)	(12.2)
Total deferred	28.7	(90.7)	(14.0)
Investment tax credits, net	(2.6)	(62.0)	(2.6)
Income tax expense/(benefit)	$ 52.4	$ (44.0)	$ 32.2

A reconciliation between income tax expense/(benefit) and the expected tax expense at the statutory rate is as follows:

	For the Years Ended December 31,		
	2007	2006	2005
	(Millions of Dollars, except percentages)		
Income before income tax expense/(benefit)	$ 185.9	$ 156.0	$ 127.0
Expected federal income tax expense	65.1	54.6	44.5
Tax effect of differences:			
Depreciation	(6.6)	(1.8)	(3.9)
Investment tax credit amortization (including $59.3 million related to the PLR in 2006)	(2.6)	(62.0)	(2.6)
State income taxes, net of federal impact	(11.9)	(7.4)	(5.3)
Excess deferred income taxes - PLR	-	(14.7)	-
Deferred tax adjustment - sale to affiliate	-	(4.4)	-
Tax asset valuation reserve adjustment	9.8	(3.8)	-
Medicare subsidy	(1.8)	(2.2)	(2.4)
Other, net	0.4	(2.3)	1.9
Income tax expense/(benefit)	$ 52.4	$ (44.0)	$ 32.2
Effective tax rate	28.2 %	*	25.4 %

*Not meaningful.

NU and its subsidiaries, including CL&P, file a consolidated federal income tax return and file state income tax returns. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

In 2000, CL&P requested from the Internal Revenue Service (IRS) a Private Letter Ruling (PLR) regarding the treatment of unamortized investment tax credits (UITC) and excess deferred income taxes (EDIT) related to generation assets that were sold. In 2006, the IRS issued a PLR in response to CL&P's request for a ruling, which held that it would be a violation of tax regulations if the EDIT or UITC are used to reduce customers' rates following the sale of the generation assets. CL&P's UITC and EDIT balances related to generation assets that have been sold totaled $59 million and $15 million, respectively, and $74 million combined. Later in 2006, the 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 ex pense with an increase to CL&P's earnings by the same amount.

The tax effects of temporary differences that give rise to the current and long-term net accumulated deferred tax obligations are as follows:

(Millions of Dollars)	At December 31, 2007	At December 31, 2006
Deferred tax liabilities - current:		
Property tax accruals	$ 35.3	$ 27.1
Derivative asset	21.8	17.9
Total deferred tax liabilities - current	57.1	45.0
Deferred tax assets - current:		
Allowance for uncollectible accounts	14.6	15.9
Other	1.7	1.6
Total deferred tax assets - current	16.3	17.5
Net deferred tax liabilities - current	40.8	27.5
Deferred tax liabilities - long-term:		
Accelerated depreciation and other plant-related differences	546.8	529.6
Employee benefits	133.2	94.5
Regulatory amounts:		
Securitized contract termination costs	28.2	36.6
Other regulatory deferrals	70.8	101.9
Income tax gross-up	161.3	168.4
Derivative assets	111.1	99.5
Other	16.0	20.2
Total deferred tax liabilities - long-term	1,067.4	1,050.7
Deferred tax assets - long-term:		
Regulatory deferrals	168.5	194.9
Employee benefits	63.6	64.7
Income tax gross-up	18.2	21.3
Derivative liability	54.2	12.7
Other	64.1	37.6
Total deferred tax assets - long-term	368.6	331.2
Net deferred tax liabilities - long-term	698.8	719.5
Net deferred tax liabilities	$ 739.6	$ 747.0

At December 31, 2007, CL&P had state tax credit carry forwards of $38 million that expire by 2012. At December 31, 2006, CL&P had state tax credit carry forwards of $11.7 million that expire by 2011.

Effective on January 1, 2007, CL&P 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, CL&P recorded estimates for uncertain tax positions in accordance with SFAS No. 5, "Accounting for Contingencies."

As a result of implementing FIN 48, CL&P recognized a cumulative effect of a change in accounting principle of $24 million as a reduction to the January 1, 2007 balance of retained earnings. Refer to the accompanying consolidated quarterly financial data (unaudited) that discusses a correction in the company’s initial adoption of FIN 48.

Interest and Penalties: Effective on January 1, 2007, CL&P's accounting policy for the classification of interest and penalties related to FIN 48 is as follows:

- Interest on uncertain tax positions is recorded and classified as a component of other interest expense. CL&P recorded accrued interest expense of $8.7 million, which is included in the cumulative effect of a change in accounting principle, as of January 1, 2007. For the year ended December 31, 2007, CL&P recorded interest expense of $2.3 million. At December 31, 2007, $11 million of accrued interest expense was recognized on the accompanying consolidated balance sheet.

- No penalties have been recorded under FIN 48. If penalties are recorded in the future, then the estimated penalties would be classified as a component of other income/(loss), net.

Unrecognized Tax Benefits: Upon adoption of FIN 48 on January 1, 2007, CL&P had unrecognized tax benefits totaling $62.6 million, of which $39.7 million would impact the effective tax rate, if recognized. As of December 31, 2007, CL&P's unrecognized tax benefits totaled $75.9 million, of which $62.3 million would impact the effective tax rate, if recognized.

A reconciliation of the activity in unrecognized tax benefits from January 1, 2007 to December 31, 2007 is as follows:

(Millions of Dollars)		
Balance at beginning of year	$	62.6
Gross increases - current year		23.5
Gross decreases - prior year		10.2
Balance at end of year	$	75.9

Tax Positions: NU is currently working to resolve all open tax years. It is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. Management estimates that potential resolutions could result in a zero to $12 million decrease in unrecognized tax benefits by CL&P. This estimated change is primarily related to the timing of deducting expenses for book versus tax purposes, which is not expected to have a material impact on earnings.

Tax Years: The following table summarizes CL&P's tax years that remain subject to examination by major tax jurisdictions at December 31, 2007:

Description	**Tax Years**
Federal (NU consolidated)	2002 - 2007
Connecticut	1997 - 2007

H. Property, Plant and Equipment and Depreciation

The following table summarizes CL&P's investments in utility plant at December 31, 2007 and 2006 and the average depreciable life at December 31, 2007:

		At December 31,	
	Average Depreciable Life	**2007**	**2006**
	(Years)	*(Millions of Dollars)*	
Distribution	28.7	$ 3,559.3	$ 3,458.3
Transmission	46.1	1,339.8	1,098.9
Total property, plant and equipment		4,899.1	4,557.2
Less: Accumulated depreciation		(1,279.7)	(1,260.5)
Net property, plant and equipment		3,619.4	3,296.7
Construction work in progress		782.4	337.7
Total property, plant and equipment, net		$ 4,401.8	$ 3,634.4

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 DPUC. Depreciation rates are applied to plant-in-service from the time it is placed in service. When a plant is retired from service, the original cost of the plant is charged to the accumulated provision for depreciation which includes cost of removal less salvage. Cost of removal is classified as a regulatory liability. The depreciation rates for the several classes of utility plant-in-service are equivalent to a composite rate of 3.3 percent in 2007, and 3.5 percent in 2006 and 2005.

I. Equity Method Investments

At December 31, 2007, CL&P owned common stock in three regional nuclear companies (Yankee Companies). Each of the Yankee Companies owned a single nuclear generating plant which has been decommissioned. CL&P's ownership interests in the Yankee Companies at December 31, 2007, which are accounted for on the equity method, were 34.5 percent of CYAPC, 24.5 percent of YAEC and 12 percent of MYAPC. The total carrying value of CL&P's ownership interest in CYAPC, MYAPC and YAEC, which is included in deferred debits and other assets - other on the accompanying consolidated balance sheets and the distribution reportable segment, totaled $4.6 million and $6.6 million at December 31, 2007 and 2006, respectively. Earnings related to these equity investments are included in other income, net on the accompanying consolidated statements of income. For further information, see Note 1P, " Summary of Significant Accounting Policies - Other Income, Net," to the consolidated financial statements.

For further information, see Note 5E, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements.

J. Allowance for Funds Used During Construction

AFUDC is included in the cost of CL&P's plant and represents the cost of borrowed and equity funds used to finance construction. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of other interest expense, and the AFUDC related to equity funds is recorded as other income on the consolidated statements of income.

	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	**2007**	**2006**	**2005**
AFUDC:			
Borrowed funds	$ 10.9	$ 6.6	$ 6.7
Equity funds	14.2	7.6	9.8
Totals	$ 25.1	$ 14.2	$ 16.5
Average AFUDC rate	8.0 %	7.9 %	7.9 %

CL&P's average AFUDC rate is based on a FERC-prescribed formula that develops an average rate using the cost of a company's short-term financings as well as a company's capitalization (preferred stock, long-term debt and common equity). The average rate is applied to eligible CWIP amounts to calculate AFUDC. Although AFUDC is recorded on 100 percent of CL&P's CWIP for its major transmission projects in southwest Connecticut, 50 percent of this AFUDC is being reserved as a regulatory liability to reflect current rate base recovery for 50 percent of the CWIP as a result of FERC approved transmission incentives.

K. Sale of Customer Receivables

CRC, a consolidated, wholly-owned subsidiary of CL&P, is permitted to sell up to $100 million of an undivided interest in CL&P's accounts receivable and unbilled receivables to a financial institution. At December 31, 2007, there were $20 million in sales. At December 31, 2006, there were no such sales.

At December 31, 2007 and 2006, amounts sold to CRC by CL&P but not sold to the financial institution totaling $308.2 million and $375.7 million, respectively, were included in investments in securitizable assets on the accompanying consolidated balance sheets. These amounts would be excluded from CL&P's assets in the event of CL&P's bankruptcy.

On July 3, 2007, CL&P extended the bank commitment under the Receivables Purchase and Sale Agreement with CRC and the financial institution through June 30, 2008 and extended the facility termination date to June 21, 2012. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to the servicing of those receivables.

The transfer of receivables to the financial institution under this arrangement qualifies for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities - A Replacement of SFAS No. 125."

L. Asset Retirement Obligations

CL&P implemented FIN 47 on December 31, 2005. FIN 47 requires an entity to recognize a liability for the fair value of an asset retirement obligation (ARO) on the obligation date if the liability's fair value can be reasonably estimated and is conditional on a future event. FIN 47 provides that settlement dates and future costs should be reasonably estimated when sufficient information becomes available and provides guidance on the definition and timing of sufficient information in determining expected cash flows and fair values. Management has identified various categories of AROs, primarily certain assets containing asbestos and hazardous contamination. A fair value calculation, reflecting expected probabilities for settlement scenarios, has been performed.

Because it is a cost-of-service, rate regulated entity, CL&P applies regulatory accounting in accordance with SFAS No. 71, and the costs associated with CL&P’s AROs were included in other regulatory assets at December 31, 2007 and 2006.

The fair value of the AROs was recorded as a liability in deferred credits and other liabilities – other with an offset included in property, plant and equipment on the accompanying consolidated balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively. Both the depreciation and accretion were recorded as increases to regulatory assets on the accompanying consolidated balance sheets at December 31, 2007 and 2006.

The following tables present the ARO asset, the related accumulated depreciation, the regulatory asset, and the ARO liabilities at December 31, 2007 and 2006:

	At December 31, 2007			
(Millions of Dollars)	**ARO Asset**	**Accumulated Depreciation of ARO Asset**	**Regulatory Asset**	**ARO Liabilities**
Asbestos	$ 1.6	$ (1.0)	$ 11.2	$ (11.8)
Hazardous contamination	3.5	(0.9)	7.6	(10.2)
Other AROs	5.7	(2.5)	3.4	(6.6)
Total AROs	$ 10.8	$ (4.4)	$ 22.2	$ (28.6)

	At December 31, 2006			
(Millions of Dollars)	**ARO Asset**	**Accumulated Depreciation of ARO Asset**	**Regulatory Asset**	**ARO Liabilities**
Asbestos	$ 2.3	$ (1.3)	$ 10.8	$ (11.8)
Hazardous contamination	4.9	(1.2)	8.5	(12.2)
Other AROs	10.4	(5.1)	6.5	(11.8)
Total AROs	$ 17.6	$ (7.6)	$ 25.8	$ (35.8)

A reconciliation of the beginning and ending carrying amounts of CL&P's AROs is as follows:

(Millions of Dollars)	**2007**	**2006**
Balance at beginning of year	$ (35.8)	$ (35.9)
Liabilities incurred during the period	(2.8)	(4.7)
Liabilities settled during the period	7.1	1.6
Accretion	(0.8)	(0.2)
Change in estimates	4.2	1.7
Revisions in estimated cash flows	(0.5)	1.7
Balance at end of year	$ (28.6)	$ (35.8)

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.

M. Materials and Supplies

Materials and supplies include materials purchased primarily for construction, operation and maintenance (O&M) purposes. Materials and supplies are valued at the lower of average cost or market.

N. Special Deposits

CL&P had amounts on deposit related to a special purpose entity used to facilitate the issuance of rate reduction certificates. These amounts totaled $14.4 million and $70.1 million at December 31, 2007 and 2006, respectively. In addition, the company had $5.8 million and $6.5 million in other cash deposits held with unaffiliated parties at December 31, 2007 and 2006, respectively, primarily related to CL&P's transmission projects. These amounts are included in deferred debits and other assets - other on the accompanying consolidated balance sheets.

O. Other Taxes

Certain excise taxes levied by state or local governments are collected by CL&P from its customers. These excise taxes are accounted for on a gross basis with collections in revenues and payments in expenses. For the years ended December 31, 2007, 2006 and 2005, gross receipts taxes, franchise taxes and other excise taxes of $95 million, $92.7 million and $88.2 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 from its customers as the agent for state and local governments and are recorded on a net basis with no impact on the accompanying consolidated statements of income.

P. Other Income, Net

The pre-tax components of CL&P's other income/(loss) items are as follows:

(Millions of Dollars)	For the Years Ended December 31, 2007	2006	2005
Other Income:			
AFUDC - equity funds	$ 14.2	$ 7.6	$ 9.8
Energy Independence Act incentives	9.9	5.5	-
Investment income	7.7	9.8	10.8
Conservation and load management incentives	5.5	4.2	4.4
Procurement fee	-	11.0	17.8
Equity in earnings of regional nuclear generating companies	1.9	(0.9)	1.2
Rental investment revenue	0.7	0.7	1.1
Total Other Income	39.9	37.9	45.1
Other Loss:			
Rental investment expenses	(0.1)	(0.1)	(0.1)
Total Other Loss	(0.1)	(0.1)	(0.1)
Total Other Income, Net	$ 39.8	$ 37.8	$ 45.0

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.

The 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.

Equity in earnings of regional nuclear generating companies relates to CL&P's investment in the Yankee Companies.

Q. Provision for Uncollectible Accounts

CL&P maintains a provision for uncollectible accounts to record its receivables at an estimated net realizable value. This provision is determined based upon a variety of factors, including applying an estimated uncollectible account percentage to each receivable aging category, historical collection and write-off experience and management's assessment of collectibility from individual customers. Management reviews at least quarterly the collectibility of the receivables, and if circumstances change, collectibility estimates are adjusted accordingly. Receivable balances are written-off against the provision for uncollectible accounts when these balances are deemed to be uncollectible.

In November of 2006, the DPUC issued an order allowing CL&P to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2007, CL&P had uncollectible hardship accounts receivable reserves in the amount of $24 million. At December 31, 2006, these amounts totaled $17 million. CL&P recorded regulatory assets for the unamortized portion as these amounts are probable of recovery. Prior to the order, any write-offs of these amounts were deferred for recovery at the time of write-off. The CL&P reserve offsets amounts sold to CRC by CL&P but not sold to the financial institution, which are classified as investments in securitizable assets on the accompanying consolidated balance sheets.

2. Short-Term Debt

Limits: The amount of short-term borrowings that may be incurred by CL&P is subject to periodic approval by either the FERC or the DPUC. On December 12, 2007, the FERC granted authorization to allow CL&P to incur total short-term borrowings up to a maximum of $450 million, effective from December 31, 2007, through December 31, 2009.

The charter of CL&P contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur. In November of 2003, CL&P obtained authorization from its preferred stockholders for a ten-year period expiring in March of 2014 to issue unsecured indebtedness with a maturity of less than 10 years in excess of the 10 percent of total capitalization limitation in CL&P's charter, provided that all unsecured indebtedness would not exceed 20 percent of total capitalization. On March 18, 2004, the SEC approved this change in CL&P's charter. As of December 31, 2007, CL&P was permitted to incur $765.7 million of additional unsecured debt under this provision.

Credit Agreement: CL&P is a party, along with other NU subsidiaries, to a five-year unsecured revolving credit facility which expires on November 6, 2010. CL&P may draw up to $200 million under this facility on a short-term basis or long-term basis, subject to regulatory approvals. At December 31, 2007 and 2006, CL&P had no borrowings outstanding under this facility.

Pool: CL&P is a member of the NU Money Pool (Pool). The Pool provides a more efficient use of cash resources of NU and reduces outside short-term borrowings. NUSCO administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are first met with available funds of other member companies, including funds borrowed by NU. NU may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on loans from NU, however, bear interest at NU's cost and must be repaid based upon the terms of NU's original borrowing. At December 31, 2007 and

2006, CL&P had borrowings of $38.8 million and $258.9 million from the Pool, respectively. The weighted average interest rate on borrowings from the Pool for the years ended December 31, 2007 and 2006 was 5.04 percent and 4.97 percent, respectively.

3. Derivative Instruments

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, 2007 included a derivative asset with a fair value of $311.2 million and a derivative liability with a fair value of $31.8 million. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of stranded costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates. At December 31, 2006, the fair values of these derivatives included a derivative asset with a fair value of $289.6 million and a derivative liability with a fair value of $35.6 million.

CL&P has entered into Financial Transmission Rights contracts and bilateral basis swaps to limit the congestion costs associated with its standard offer contracts. An offsetting regulatory asset or liability has been recorded as management believes that these costs will be recovered or refunded in rates. At December 31, 2007, the fair value of these derivative contracts was recorded as a derivative asset of $1.4 million and a derivative liability of $1.3 million on the accompanying consolidated balance sheets. At December 31, 2006, the fair value of those derivative contracts was recorded as a derivative asset of $4.9 million and a derivative liability of $0.4 million on the accompanying consolidated balance sheets.

Pursuant to Public Act 05-01, "An Act Concerning Energy Independence," in August of 2007 the DPUC approved two CL&P contracts associated with the capacity of two generating projects to be built or modified. The DPUC also approved two capacity-related contracts entered into by The United Illuminating Company (UI), one with a generating project to be built and one with a new demand response project. The total capacity of these four projects is expected to be approximately 787 megawatts (MW). The contracts, referred to as CfDs, obligate the utilities' customers to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs, with 80 percent to CL&P and 20 percent to UI. The ultimate cos t to CL&P under the derivative contracts will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. Due to the significance of the non-observable capacity prices associated with modeling the fair values of these derivative contracts, their initial negative fair values at inception of approximately $100 million have not been reflected in the accompanying consolidated financial statements. At December 31, 2007, the changes in fair value of these CfDs since inception are recorded as a $107.1 million derivative liability on the consolidated balance sheet. A derivative asset of $20.8 million has been recorded to reflect UI’s 20 percent share of these amounts and the change in fair value of one of the CfD contracts. An offsetting regulatory asset and liability for the remaining 80 percent of the changes in fair value of the contracts since inception has been recorded as management believes these amounts will be recovered or refunded in cost-of-service, regulated rates. On October 5, 2007, NRG Energy, Inc. (NRG) filed in New Britain Superior Court an appeal of the DPUC's decision selecting the CfDs. This appeal was taken into consideration in valuing the CfDs and had the effect of reducing the net negative derivative values by approximately $215 million at December 31, 2007. On February 13, 2008, the New Britain Superior Court judge denied NRG's appeal. The effect of this denial will be reflected as an increase in negative derivative values in the first quarter of 2008.

Interest Rate Hedging: In December of 2007, CL&P entered into two forward interest rate swap agreements to hedge the interest cash outflows associated with two proposed debt issuances of $150 million each in November of 2008. The interest rate swaps are based on a 10-year LIBOR swap rate and match the index used for the debt issuances. As cash flow hedges, at December 31, 2007, the fair value of these hedges was recorded as a $2.3 million derivative asset on the consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

4. Employee Benefits

A. Pension Benefits and Postretirement Benefits Other Than Pensions

On December 31, 2006, CL&P implemented SFAS No. 158, which applies to NU’s Pension Plan, SERP, and PBOP Plan and required CL&P to record the funded status of these plans based on the projected benefit obligation for the Pension Plan and accumulated postretirement benefit obligation (APBO) for the PBOP Plan on the consolidated balance sheets at December 31, 2007 and 2006. SFAS No. 158 requires the additional liability to be recorded with an offset to accumulated other comprehensive income in shareholders' equity. This amount is remeasured annually, or as circumstances dictate. However, because CL&P is a cost-of-service, rate regulated entity under SFAS No. 71, regulatory assets were recorded in the amount of $72.2 million and $155.8 million at December 31, 2007 and 2006, respectively, as these benefits expense amounts have been and continue to be recoverable in cost-of-service, regulated rates. &n bsp;Regulatory accounting was also applied to the portions of the NUSCO costs that support CL&P, as these amounts are also recoverable.

Pension Benefits: CL&P participates in a uniform non-contributory defined benefit retirement plan (Pension Plan) covering substantially all regular CL&P employees. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. CL&P uses a December 31st measurement date for the Pension Plan. Pension (income)/expense affecting earnings is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2007**	**2006**	**2005**
Total pension (income)/expense	$ (15.6)	$ 0.3	$ 3.0
Income/(expense) capitalized as utility plant	7.3	0.1	(1.5)
Total pension (income)/expense, net of amounts capitalized	$ (8.3)	$ 0.4	$ 1.5

Total pension (income)/expense above includes pension curtailments and termination benefits of $2.1 million in 2006 and expense of $3.6 million in 2005, respectively. No pension curtailments and termination benefits were recorded in 2007.

Pension Curtailments and Termination Benefits: In December of 2005, a new program was approved allowing then current employees to elect to receive retirement benefits under a new 401(k) benefit rather than under the Pension Plan. The approval of the new plan resulted in recording an estimated pre-capitalization, pre-tax curtailment expense of $1.3 million in 2005, as a certain number of employees were expected to elect the new 401(k) benefit, resulting in a reduction in aggregate estimated future years of service under the Pension Plan. Because the predicted level of elections of the new benefit did not occur, CL&P recorded a pre-capitalization, pre-tax reduction in the curtailment expense of $0.8 million in 2006.

As a result of its corporate reorganization in 2005, CL&P recorded a combined pre-capitalization, pre-tax curtailment expense and related termination benefits for the Pension Plan totaling $2.3 million. Based on a revised estimate of expected headcount reduction in 2006, CL&P 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 $0.5 million and a reduction in termination benefits expense of $0.8 million totaling a net $1.3 million reduction to pension expense.

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 CL&P's Pension Plan benefit obligation by $17.1 million and was reflected as a prior service cost and as a decrease in the funded status of the Pension Plan. This amount will be amortized over a 12-year period representing average remaining service lives of employees.

Market-Related Value of Pension Plan Assets: CL&P bases the actuarial determination of pension plan income or expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets and are included in actuarial gains and losses. Since the market-related valuation calculation recognizes gains or losses over a four-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

SERP: NU has maintained a SERP since 1987. The SERP provides its eligible participants, some of which are officers of CL&P, 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.

PBOP: CL&P provides certain health care benefits, primarily medical and dental, and life insurance benefits through a PBOP Plan. These benefits are available for employees retiring from CL&P 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. CL&P uses a December 31st measurement date for the PBOP Plan.

CL&P annually funds postretirement costs through external trusts with amounts that have been and will continue to be recovered in rates and that are tax deductible. Currently, there are no pending regulatory actions regarding postretirement benefit costs.

PBOP Curtailments and Termination Benefits: CL&P recorded an estimated $2.5 million pre-tax curtailment expense at December 31, 2005 relating to its corporate reorganization. CL&P also accrued a $0.2 million pre-tax termination benefit expense at December 31, 2005 relating to certain benefits provided under the terms of the PBOP Plan. Based on refinements to its estimates, CL&P recorded an adjustment to the curtailment and related termination benefits in 2006. This adjustment resulted in a combined pre-capitalization, pre-tax reduction in the curtailment expense and termination benefits of $1.5 million in 2006. There were no curtailments or termination benefits recorded in 2007.

The following table represents information on the plans' benefit obligation, fair value of plan assets and funded status:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Change in benefit obligation						
Benefit obligation at beginning of year	$ (860.5)	$ (859.3)	$ (2.6)	$ (2.6)	$ (187.1)	$ (200.7)
Service cost	(16.2)	(17.0)	-	(0.1)	(2.3)	(2.9)
Interest cost	(48.8)	(47.9)	(0.1)	(0.1)	(10.2)	(11.1)
Transfers	-	-	-	-	(0.3)	3.4
Actuarial gain/(loss)	80.7	21.6	0.2	0.1	(1.6)	9.5
Prior service cost	(17.1)	-	-	-	-	-
Federal subsidy on benefits paid	-	-	-	-	(1.4)	(1.3)
Benefits paid - excluding lump sum payments	52.4	49.6	0.1	0.1	18.0	16.1
Curtailment/impact of plan changes	-	(8.3)	-	-	-	(0.1)
Termination benefits	-	0.8	-	-	-	-
Benefit obligation at end of year	$ (809.5)	$ (860.5)	$ (2.4)	$ (2.6)	$ (184.9)	$ (187.1)
Change in plan assets						
Fair value of plan assets at beginning of year	$ 1,103.7	$ 990.7	N/A	N/A	$ 101.3	$ 85.1
Actual return on plan assets	93.0	162.5	N/A	N/A	5.9	12.7
Employer contribution	-	-	N/A	N/A	16.9	21.5
Transfers	-	-	N/A	N/A	0.2	(1.9)
Benefits paid - excluding lump sum payments	(52.4)	(49.6)	N/A	N/A	(18.0)	(16.1)
Fair value of plan assets at end of year	$ 1,144.3	$ 1,103.6	$ N/A	$ N/A	$ 106.3	$ 101.3
Funded status at December 31st	$ 334.8	$ 243.1	$ (2.4)	$ (2.6)	$ (78.6)	$ (85.8)

The amounts recognized on the accompanying consolidated balance sheets for the funded status above at December 31, 2007 and 2006 is as follows:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Prepaid pension	$ 334.8	$ 243.1	$ -	$ -	$ -	$ -
Other current liabilities	-	-	(0.1)	(0.1)	-	-
Other deferred credits and other liabilities	-	-	(2.3)	(2.5)	-	-
Accrued postretirement benefits	-	-	-	-	(78.6)	(85.8)

In 2005, as a result of the expected transition of employees into the new 401(k) benefit and the company's corporate reorganization, NU reduced CL&P's share of the Pension Plan's obligation via a curtailment benefit related to the reduction in the future years of service expected to be rendered by plan participants. This overall reduction in plan obligation served to reduce the previously unrecognized actuarial losses. In 2006, $8.3 million of this curtailment was reversed because actual levels of elections of the new 401(k) benefit were much lower than expected and is reflected above as an increase to the obligation.

For the Pension Plan, the company amortizes its transition obligation over the remaining service lives of its employees as calculated for CL&P on an individual subsidiary basis and amortizes the prior service cost and unrecognized net actuarial loss over the remaining service lives of its employees as calculated on an NU consolidated basis. For the PBOP Plan, the company amortizes its transition obligation, prior service cost, and unrecognized net actuarial loss over the remaining service lives of its employees as calculated for CL&P on an individual subsidiary basis.

Although the SERP does not have any plan assets, benefit payments are supported by earnings on marketable securities held by NU.

The accumulated benefit obligation for the Pension Plan was $723.2 million and $771.1 million at December 31, 2007 and 2006, respectively, and $2.2 million and $2.4 million for the SERP at December 31, 2007 and 2006, respectively.

The following is a summary of amounts recorded as regulatory assets as a result of SFAS No. 158 at December 31, 2007 and 2006 and the changes in those amounts recorded during the years (millions of dollars):

	At December 31,					
	Pension		SERP		PBOP	
	2007	2006	2007	2006	2007	2006
Transition obligation at beginning of year	$ -	$ -	$ -	$ -	$ 36.7	$ -
Amounts recorded upon adoption of SFAS No. 158	-	-	-	-	-	36.7
Amounts reclassified as net periodic benefit expense	-	-	-	-	(6.1)	-
Transition obligation at end of year	$ -	$ -	$ -	$ -	$ 30.6	$ 36.7
Prior service cost at beginning of year	$ 16.4	$ -	$ 0.2	$ -	$ -	$ -
Amounts reclassified as net periodic benefit expense	(3.8)	-	(0.1)	-	-	-
Prior service cost arising during the year (1)	17.1	16.4	-	0.2	-	-
Prior service cost at end of year	$ 29.7	$ 16.4	$ 0.1	$ 0.2	$ -	$ -
Net actuarial losses at beginning of year	$ 55.7	$ -	$ 1.0	$ -	$ 45.8	$ -
Amounts reclassified as net periodic benefit expense	(6.3)	-	(0.1)	-	(4.7)	-
Actuarial (gains)/losses arising during the year (1)	(83.1)	55.7	(0.2)	1.0	3.7	45.8
Actuarial (gains)/losses at end of year	$ (33.7)	$ 55.7	$ 0.7	$ 1.0	$ 44.8	$ 45.8
Total deferred benefit costs as regulatory assets	$ (4.0)	72.1	$ 0.8	$ 1.2	$ 75.4	$ 82.5

(1) Amounts arising for prior service cost and actuarial (gains)/losses in 2006 relate to the initial adoption of SFAS No. 158.

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2008 are as follows (millions of dollars):

	Estimated Expense in 2008		
	Pension	SERP	PBOP
Transition obligation	$ -	$ -	$ 6.1
Prior service cost	4.3	-	-
Net actuarial loss	1.3	0.1	4.4
Total	$ 5.6	$ 0.1	$ 10.5

The following actuarial assumptions were used in calculating the plans' year end funded status:

	At December 31,			
	Pension and SERP Benefits		Postretirement Benefits	
Balance Sheets	2007	2006	2007	2006
Discount rate	6.60 %	5.90 %	6.35 %	5.80 %
Compensation/progression rate	4.00 %	4.00 %	N/A	N/A
Health care cost trend rate	N/A	N/A	8.50 %	9.00 %

The components of net periodic (income)/expense are as follows:

	For the Years Ended December 31,								
	Pension Benefits			SERP Benefits			Postretirement Benefits		
(Millions of Dollars)	2007	2006	2005	2007	2006	2005	2007	2006	2005
Service cost	$ 16.2	$ 17.0	$ 17.2	$ -	$ 0.1	$ -	$ 2.3	$ 2.9	$ 2.8
Interest cost	48.8	47.9	46.8	0.1	0.1	0.1	10.2	11.1	10.2
Expected return on plan assets	(90.7)	(81.2)	(80.1)	-	-	-	(7.2)	(5.6)	(4.9)
Net transition obligation cost	-	-	-	-	-	-	6.1	6.1	6.3
Prior service cost	3.8	2.8	3.0	0.1	-	-	-	-	-
Actuarial loss	6.3	15.9	12.5	0.1	0.1	0.1	4.7	7.1	7.1
Net periodic (income)/expense - before curtailments and termination (benefits)/expense	(15.6)	2.4	(0.6)	0.3	0.3	0.2	16.1	21.6	21.5
Curtailment (benefits)/expense	-	(1.3)	2.3	-	-	-	-	(1.4)	2.5
Termination (benefits)/expense	-	(0.8)	1.3	-	-	-	-	(0.1)	0.2
Total curtailments and termination (benefits)/expense	- -	(2.1)	3.6	- -	- -	- -	- -	(1.5)	2.7
Total - net periodic (income)/expense	(15.6) $	0.3 $	3.0 $	0.3 $	0.3 $	0.2 $	16.1 $	20.1 $	24.2 $

Not included in the pension (income)/expense amounts above are pension related intercompany allocations totaling $9.3 million, $10.3 million, and $8.8 million for the years ended December 31, 2007, 2006 and 2005, respectively, including curtailment and termination benefits income of $1.5 million and expense of $2.4 million for the years ended December 31, 2006 and 2005, respectively. Excluded from postretirement benefits expense are related intercompany allocations of $7.4 million, $7.6 million and $7.9 million for the years ended December 31, 2007, 2006, and 2005, respectively, including curtailments and termination benefits of $0.3 million and expense of $0.7 million, for the years ended December 31, 2006 and 2005, respectively. Excluded from SERP expenses are related intercompany allocations of $1.9 million, $2 million and $1.9 million for the years ended December 31, 2007, 2006 and 2005, r espectively. These amounts are included in other operating expenses on the accompanying consolidated statements of income.

The following assumptions were used to calculate pension and postretirement benefit expense and income amounts:

	For the Years Ended December 31,					
Statements of Income	**Pension Benefits and SERP**			**Postretirement Benefits**		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Discount rate	5.95 % (1)	5.80 %	6.00 %	5.80 %	5.65 %	5.50 %
Expected long-term rate of return	8.75 %	8.75 %	8.75 %	N/A	N/A	N/A
Compensation/progression rate	4.00 %	4.00 %	4.00 %	N/A	N/A	N/A
Expected long-term rate of return -						
Health assets, net of tax	N/A	N/A	N/A	6.85 %	6.85 %	6.85 %
Life assets and non-taxable health assets	N/A	N/A	N/A	8.75 %	8.75 %	8.75 %

(1) The 2007 discount rate for the SERP was 5.9 percent.

The following table represents the PBOP assumed health care cost trend rate for the next year and the assumed ultimate trend rate:

	Year Following December 31,	
	2007	**2006**
Health care cost trend rate assumed for next year	8.50 %	9.00 %
Rate to which health care cost trend rate is assumed to decline (the ultimate trend rate)	5.00 %	5.00 %
Year that the rate reaches the ultimate trend rate	2015	2011

At December 31, 2007, the health care cost trend assumption was reset for 2008 at 8.5 percent, decreasing one-half percentage point per year to an ultimate rate of 5 percent in 2015.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point in each year would have the following effects:

(Millions of Dollars)	**One Percentage Point Increase**	**One Percentage Point Decrease**
Effect on total service and interest cost components	$0.4	$(0.3)
Effect on postretirement benefit obligation	$5.5	$(4.8)

NU's investment strategy for its Pension Plan and PBOP Plan is to maximize the long-term rate of return on those plans' assets within an acceptable level of risk. The investment strategy establishes target allocations, which are routinely reviewed and periodically rebalanced. NU's expected long-term rates of return on Pension Plan assets and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, NU also evaluated input from actuaries and consultants, as well as long-term inflation assumptions and NU's historical 25-year compounded return of approximately 11.8 percent. The Pension Plan's and PBOP Plan's target asset allocation assumptions and expected long-term rate of return assumptions by asset category are as follows:

	At December 31,					
	Pension Benefits				**Postretirement Benefits**	
	2007		**2006**		**2007 and 2006**	
	Target Asset Allocation	**Assumed Rate of Return**	**Target Asset Allocation**	**Assumed Rate of Return**	**Target Asset Allocation**	**Assumed Rate of Return**
Equity Securities:						
United States	40%	9.25%	45%	9.25%	55%	9.25%
Non-United States	17%	9.25%	14%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	3%	10.25%	2%	10.25%
Private	8%	14.25%	8%	14.25%	-	-
Debt Securities:						
Fixed income	25%	5.50%	20%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%	5%	7.50%
Real Estate	5%	7.50%	5%	7.50%	-	-

The actual asset allocations at December 31, 2007 and 2006 approximated these target asset allocations. The plans' actual weighted-average asset allocations by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
Asset Category	**2007**	**2006**	**2007**	**2006**
Equity Securities:				
United States	40%	46%	55%	54%
Non-United States	17%	16%	14%	14%
Emerging markets	5%	4%	1%	1%
Private	7%	5%	-	-
Debt Securities:				
Fixed income	26%	19%	29%	29%
High yield fixed income	-	5%	1%	2%
Real Estate	5%	5%	-	-
Total	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	Government Benefits
2008	$ 53.4	0.1	18.9	(1.7)
2009	54.8	0.1	19.1	(1.8)
2010	55.7	0.1	19.1	(1.9)
2011	56.5	0.1	19.0	(2.0)
2012	57.5	0.2	18.9	(2.2)
2013-2017	305.1	1.0	90.9	(12.4)

The government benefits represent amounts expected to be received from the federal government for the new Medicare prescription drug benefit under the PBOP Plan related to the corresponding year's benefit payments.

Contributions: Currently, CL&P's policy is to annually fund the Pension Plan an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code. CL&P does not expect to make any contributions to the Pension Plan in 2008. For the PBOP plan, it is currently CL&P's policy to annually fund an amount equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits. CL&P contributed $15.8 million for the year ended December 31, 2007 to fund the PBOP Plan and expects to make $15.7 million in contributions to the PBOP Plan in 2008. Beginning in 2007, CL&P made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $1.1 million in 2007 and is estimated to be $1.8 million in 2008.

B. Defined Contribution Plans

NU maintains a 401(k) Savings Plan for substantially all CL&P employees. This savings plan provides for employee contributions up to specified limits. NU matches employee contributions up to a maximum of three percent of eligible compensation with one percent in cash and two percent in NU common shares. The 401(k) matching contributions of cash and NU common shares made by NU to CL&P employees were $3.6 million in both 2007 and 2006 and $3.7 million in 2005.

Effective on January 1, 2006, all newly hired and non-bargaining unit employees of CL&P participate in a new defined contribution savings plan called the K-Vantage benefit. These employees are not eligible to participate in the existing defined benefit Pension Plan. In addition, participants in the Pension Plan at January 1, 2006 were given the opportunity to choose to become a participant in the K-Vantage benefit beginning in 2007, in which case their benefit under the Pension Plan would be frozen. NU makes contributions to the K-Vantage benefit based on a percentage of participants' eligible compensation, as defined by the benefit document. The contributions made by NU to CL&P employees were approximately $71 thousand in 2007 and $6 thousand in 2006.

C. 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 CL&P employees and officers are entitled to participate. CL&P records compensation cost related to these plans, as applicable, for shares issued or sold to CL&P employees and officers, as well as the allocation of costs associated with shares issued or sold to NUSCO employees and officers that support CL&P. 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 CL&P's net income.

SFAS No. 123(R) requires that share-based payments be recorded using the fair value-based method based on the fair value at the date of grant and applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed. For prior periods, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," and related guidance, NU used the intrinsic value method and disclosed the pro forma effects as if NU recorded equity-based compensation under the fair value-based method.

Under SFAS No. 123(R), NU accounts for its various share-based plans as follows:

- For grants of restricted shares and restricted share units (RSUs), NU records compensation expense over the vesting period based upon the fair value of NU's common shares at the date of grant but records this expense net of estimated forfeitures.

- Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.

- NU has not granted any stock options to CL&P employees or officers 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 in which CL&P participates, NU is authorized to grant up to 4.5 million new shares for various types of awards, including restricted shares, RSUs, performance units, and stock options to eligible employees and board members. At December 31, 2007 and 2006, NU had 3,055,083 and 570,494 common shares, respectively, available for issuance under the Incentive Plan.

Restricted Shares and RSUs: NU has granted restricted shares under the 2002 through 2004 incentive programs that are subject to three-year and four-year graded vesting schedules. NU has granted RSUs under the 2004 through 2007 incentive programs that are subject to three-year and four-year graded vesting schedules. RSUs are paid in shares, including amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of total NU restricted share and RSU transactions for the year ended December 31, 2007 is as follows:

Restricted Shares	Restricted Shares	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	65,674	$15.00			
Granted	-	-			
Vested	(59,424)	$14.14	$0.8		
Outstanding at December 31, 2007	6,250	$18.65	$0.1	$ -	0.2

The per share and total weighted average grant date fair value for restricted shares vested was $14.52 and $1.1 million, respectively, for the year ended December 31, 2006 and $14.60 and $1.4 million, respectively, for the year ended December 31, 2005.

The total compensation cost recognized by CL&P for its portion of the restricted shares above was approximately $39 thousand, net of taxes of approximately $26 thousand for the year ended December 31, 2007 and $0.3 million, net of taxes of $0.2 million for the years ended December 31, 2006 and 2005.

RSUs	RSUs (Units)	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	715,299	$19.41			
Granted	330,785	$28.83	$ 9.5		
Issued	(161,137)	$19.77	$ 3.2		
Forfeited	(53,947)	$20.16	$ 1.1		
Outstanding at December 31, 2007	831,000	$22.99	$19.1	$7.7	1.8

The per share and total weighted average grant date fair value for RSUs granted was $19.87 and $7.4 million, respectively, for the year ended December 31, 2006 and $18.89 and $5.8 million, respectively, for the year ended December 31, 2005. The weighted average grant date fair value per share for RSUs issued was $18.50 and $19.06 for the years ended December 31, 2006 and 2005, respectively. The total weighted average fair value of RSUs issued was $2.2 million and $1.9 million for the years ended December 31, 2006 and 2005, respectively.

The compensation cost recognized by CL&P for its portion of the RSUs above was $2.3 million, net of taxes of $1.5 million for the year ended December 31, 2007, $1.6 million, net of taxes of $1 million for the year ended 2006 and $0.8 million, net of taxes of $0.5 million for the year ended December 31, 2005.

Stock Options: Prior to 2003, NU granted stock options to certain CL&P employees. These options were fully vested as of December 31, 2005, and no compensation expense was recorded as a result of the adoption of SFAS No. 123(R). The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model.

5. Commitments and Contingencies

A. Regulatory Developments and Rate Matters

Procurement Fee Rate Proceedings: CL&P was allowed to collect a fixed procurement fee of 0.50 mills per kilowatt-hour (KWH) from customers that purchased TSO service from 2004 through the end of 2006. One mill is equal to one tenth of a cent. That fee could increase to 0.75 mills per KWH if CL&P outperforms certain regional benchmarks. CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of the procurement fee and requested approval of $5.8 million in incentive fees. On December 8, 2005, a draft decision was issued in this docket, which accepted the methodology as proposed by CL&P and authorized payment of the pre-tax $5.8 million incentive fee. On October 19, 2007, the DPUC released a recommendation prepared by its consultant relative to statistical adjustments to the incentive calculations. The DPUC has set a new schedule allow ing for rebuttal of the consultant's report. The new schedule calls for a draft decision in this docket to be issued on March 7, 2008. Management continues to believe that final regulatory approval of the $5.8 million pre tax amount, which was reflected in 2005 earnings, is probable.

B. Environmental Matters

General: CL&P 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, CL&P 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 CL&P's responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

The amounts recorded as environmental liabilities on the consolidated balance sheets represent management's best estimate of the liability for environmental costs if reasonably estimable, and take into consideration site assessment and remediation costs. Based on currently available information for estimated site assessment and remediation costs at December 31, 2007 and 2006, CL&P had $2.9 million and $2.8 million, respectively, recorded as environmental reserves. A reconciliation of the activity in these reserves at December 31, 2007 and 2006 is as follows:

	For the Years Ended December 31,	
(Millions of Dollars)	**2007**	**2006**
Balance at beginning of year	$ 2.8	$ 2.7
Additions and adjustments	0.6	0.2
Payments and adjustments	(0.5)	(0.1)
Balance at end of year	$ 2.9	$ 2.8

Of the 13 sites CL&P has currently included in the environmental reserve, four sites are in the remediation or long-term monitoring phase, eight sites have had some level of site assessment completed, and one site is in the preliminary phase of site assessment.

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

At December 31, 2007, in addition to the 13 sites, there were five sites for which there are unasserted claims; however, any related site assessment or remediation costs are not probable or estimable at this time. CL&P'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.

MGP Sites: Manufactured gas plant (MGP) sites comprise the largest portion of CL&P's environmental liability. MGPs are sites that manufactured gas from coal which produced certain byproducts that may pose a risk to human health and the environment. At both December 31, 2007 and 2006, $1.5 million represents the amount for the site assessment and remediation of MGPs.

For the three of the 13 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 the company to estimate the range of losses for environmental costs. At December 31, 2007, $1.8 million had been accrued as a liability for these sites, which represents management's best estimate of the liability for environmental costs. This amount differs from an estimated range of loss from $1.6 million to $6 million. For the ten 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 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 13 sites, two are superfund sites under CERCLA for which CL&P has been notified that it is a potentially responsible party (PRP) but for which the site assessment and remediation are not being managed by CL&P. At December 31, 2007, a liability of $0.4 million accrued on these sites of represents CL&P's estimate of its potential remediation costs with respect to these two 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: 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.

C. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982, CL&P 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 its 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), CL&P has recorded an accrual for the full liability, and payment must be made by CL&P to the DOE prior to the first delivery of spent fuel to the DOE. After the sale of Millstone, CL&P remained responsible for its share of the disposal costs associated with the Prior Period Spent Nuclear Fuel. Until such payment to the DOE is made, the outstanding liability will continue to accrue interest at the 3-month treasury bill yield rate. At December 31, 2007 and 2006, fees due to the DOE for the disposal of Prior Period Spent Nuclear Fuel are included in long-term debt and were $238.7 million and $227.5 million, respectively, including accumulated interest costs of $172.2 million and $160.9 million, respectively.

D. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of CL&P's significant long-term contractual arrangements at December 31, 2007 are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Totals
VYNPC	$ 16.6	$ 18.1	$ 17.3	$ 17.7	$ 4.3	$ -	$ 74.0
Supply/stranded cost contracts	202.2	176.3	154.0	190.4	217.6	1,301.5	2,242.0
Renewable energy contract	-	-	2.5	15.0	15.0	192.4	224.9
Hydro-Quebec	12.3	12.2	12.1	12.2	12.2	97.9	158.9
Transmission segment project commitments	529.2	52.4	100.6	278.6	264.2	108.6	1,333.6
Yankee Companies billings	23.0	19.3	20.6	18.4	18.4	53.0	152.7
Totals	$ 783.3	$ 278.3	$ 307.1	$ 532.3	$ 531.7	$ 1,753.4	$ 4,186.1

VYNPC: CL&P has commitments to buy approximately 9.5 percent of the Vermont Yankee Nuclear Power Corporation (VYNPC) plant's output through March of 2012 at a range of fixed prices. The total cost of purchases under contracts with VYNPC amounted to $15.2 million in 2007, $19.1 million in 2006 and $15.3 million in 2005.

Supply/Stranded Cost Contracts: CL&P has 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 $206 million in 2007, $206.1 million in 2006 and $148 million in 2005. The majority of the contracts expire by 2014.

In addition, CL&P and UI have entered into four CfDs for a total of approximately 787 MW of capacity with three generation projects to be built or modified and one new demand response project. The CfDs extend through 2026 and obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets. The contracts have terms of up to 15 years beginning in 2009 and are subject to a sharing agreement with UI whereby UI will share 20 percent of the costs and benefits of these contracts. The amount of CL&P's portion of the costs and benefits of these contracts included in the above table is subject to changes in capacity prices that the projects receive in the ISO-NE capacity markets and will be paid by or refunded to CL&P's customers.

These amounts do not include contractual commitments related to CL&P's standard or TSO service.

Renewable Energy Contract: CL&P has entered into an agreement to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. The contract, beginning in 2010, is an operating lease for a 15 year period with no minimum lease payments. Amounts payable under this contract are subject to a sharing agreement with UI whereby UI will share 20 percent of the costs and benefits of this contract. CL&P's portion of the costs and benefits of this contract will be paid by or refunded to CL&P's customers.

Hydro-Quebec: Along with other New England utilities, CL&P have entered into an agreement to support transmission and terminal facilities which were built to import electricity from the Hydro-Quebec system in Canada. CL&P is obligated to pay, over a 30-year period ending in 2020, its proportionate share of the annual O&M expenses and capital costs of those facilities. The total cost of this agreement amounted to $10.8 million in 2007, $11.7 million in 2006 and $12 million in 2005.

Transmission Segment Project Commitments: These amounts primarily represent commitments for various services and materials associated with CL&P's Middletown to Norwalk, Glenbrook Cables and Norwalk to Northport-Long Island, New York projects and other projects, including the New England East-West 115 kilovolt (KV) and 345 KV Overhead projects.

Yankee Companies Billings: CL&P 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 CL&P. CL&P in turn recovers these costs from its customers through DPUC-approved retail rates. The table of estimated future annual costs includes the estimated decommissioning and closure costs for CYAPC, MYAPC and YAEC.

See Note 5E, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements for information regarding the collection of the Yankee Companies' decommissioning costs.

E. Deferred Contractual Obligations

CL&P has significant decommissioning and plant closure cost obligations to the Yankee Companies, which have completed the physical decommissioning of all three of their facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P. CL&P in turn recovers these costs through DPUC-approved retail rates. CL&P's ownership interest in the Yankee Companies is 34.5 percent of CYAPC, 24.5 percent of YAEC, and 12 percent of MYAPC.

CL&P’s percentage share of the obligation to support the Yankee Companies under FERC-approved rate tariffs is the same as the ownership percentages above.

CYAPC: Under the terms of the settlement agreement between CYAPC, the DPUC, the Connecticut Office of Consumer Counsel and Maine Regulators, the parties agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars). Annual collections began in January of 2007, and were reduced from the $93 million originally requested for years 2007 through 2010 to lower levels ranging from $37 million in 2007 rising to $46 million in 2015. The reduction to annual collections was achieved by extending the collection period by 5 years through 2015 by reflecting the proceeds from a settlement agreement with Bechtel Power Corporation, by reducing collections in 2007, 2008 and 2009 by $5 million per year, and making other adjustments. Management believes CL&P will recover its share of this obligation from its customers.

YAEC: On July 31, 2006, the FERC approved a settlement agreement with the DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service previously filed by YAEC. This settlement agreement did not materially affect the level of 2006 charges. Under the settlement agreement, YAEC agreed to reduce its November 2005 decommissioning cost increase from $85 million to $79 million. Other terms of the settlement agreement include extending the collection period for charges through December 2014, reconciling and adjusting future charges based on actual decontamination and decommissioning expenses. Management believes that CL&P’s $19.4 million share of the increase in decommissioning costs will ultimately be recovered from its customers.

MYAPC: MYAPC is collecting revenues from CL&P and other owners that are adequate to recover the remaining cost of decommissioning its plant, and management expects to recover CL&P’s respective share of such 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. The Yankee Companies had claimed actual damages for the same periods as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related to disallowed spent nuclear fuel pool operating expenses.

The Court of Federal Claims, following precedent set in another case, did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. In December of 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December of 2006, the DOE appealed the ruling, and the Yankee Companies filed a cross-appeal. The refund to CL&P of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. The appeal is expected to be argued in 2008 with a decision from the Court of Appeals to follow.

CL&P's aggregate share of these damages is $29 million. Management cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, management does believe that any net settlement proceeds CL&P receives would be incorporated into FERC-approved recoveries, which would be passed on to its customers through reduced charges.

F. NRG Energy, Inc. Exposures

CL&P has entered into transactions with NRG Energy, Inc. (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. CL&P's NRG-related exposures as a result of these transactions relate to 1) the refunding of approximately $28 million of congestion charges previously withheld from NRG prior to the implementation of standard market design (SMD) on March 1, 2003, and 2) the recovery of approximately $30.2 million of CL&P's station service billings from NRG, which is currently the subject of an arbitration.

On July 20, 2007, the United States District Court for the District of Connecticut issued a ruling granting CL&P's motion for summary judgment against NRG in the pre-SMD congestion litigation. In this decision, the court held that NRG was contractually obligated to pay for congestion charges imposed during the term of the October 29, 1999 standard offer service wholesale sales agreement between CL&P and NRG and found in favor of CL&P and against NRG on each of NRG's two counterclaims. NRG did not appeal the judgment and the matter is closed.

On January 8, 2008, CL&P and NRG filed a proposed confidential settlement with the DPUC, which would settle the pending dispute concerning the scope of NRG's responsibility to pay for certain delivery service charges to CL&P. On January 28, 2008, the DPUC issued a final decision in CL&P's rate case proceeding in which it also approved the settlement between CL&P and NRG. The payment that CL&P will receive from NRG under the settlement and the rate relief approved in the January 28, 2008 DPUC decision essentially reimburses CL&P for its net station service receivable from NRG. This settlement did not and will not have an adverse effect on CL&P's consolidated net income, financial position or cash flows for the years ended December 31, 2007 and 2008, respectively.

G. Guarantees

NU provides credit assurances on behalf of subsidiaries, including CL&P, in the form of guarantees and letters of credit (LOCs) in the normal course of business. At December 31, 2007, the maximum level of exposure in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," under guarantees by NU on behalf of CL&P totaled $5.5 million. A majority of these guarantees do not have established expiration dates, and some guarantees have unlimited exposure to commodity price movements. Additionally, NU had $20 million of LOCs issued on behalf of CL&P at December 31, 2006, but did not have any LOCs issued on behalf of CL&P at December 31, 2007. CL&P has no guarantees of the performance of third parties.

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.

H. Transmission Rate Matters and FERC Regulatory Issues

As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (FERC ROE decision), CL&P recorded an estimated regulatory liability for refunds of $17.9 million as of December 31, 2006. In 2007, CL&P completed the customer refunds that were calculated in accordance with the compliance filing required by the FERC ROE decision, and refunded approximately $17 million to regional, local and localized transmission customers. The $0.9 million positive pre-tax difference ($0.5 million after-tax) between the estimated regulatory liability recorded and the actual amount refunded was recorded in 2007.

Pursuant to the October 31, 2006 FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. On August 27, 2007, NU, on behalf of CL&P, and the other New England transmission owners submitted a revised compliance filing, which outlined the regional refund process to comply with the FERC's July 26, 2007 order. In addition, the transmission owners filed a request for rehearing claiming that the FERC improperly set the floor for refunds based on the lower rates that the FERC approved in its October 31, 2006 order, rather than the last approved rates, for the period from June 3, 2005 to September 3, 2006. The FERC denied this request on January 17, 2008, and the transmission owners have until March 17, 2008 to appeal, if they so choose.

CL&P's transmission segment refunded approximately $1.6 million of revenues and interest related to the July 26, 2007 order (approximately $1 million after-tax), which was recorded in 2007.

I. Other Litigation and Legal Proceedings

NU and its subsidiaries, including CL&P, are involved in other legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, some of which involve management's best estimate of probable loss as defined by SFAS No. 5. The company records and discloses losses when these losses are probable and reasonably estimable in accordance with SFAS No. 5, discloses matters when losses are probable but not estimable, and expenses legal costs related to the defense of loss contingencies as incurred.

6. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of CL&P's fixed-rate securities is based upon the quoted market prices for those issues or similar issues. Adjustable rate securities are assumed to have a fair value equal to their carrying value. The carrying amounts of CL&P's financial instruments and the estimated fair values are as follows:

	At December 31, 2007	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**
Preferred stock not subject to mandatory redemption	$ 116.2	$ 88.2
Long-term debt -		
First mortgage bonds	1,369.8	1,362.9
Other long-term debt	662.6	674.1
Rate reduction bonds	548.7	586.2

	At December 31, 2006	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**
Preferred stock not subject to mandatory redemption	$ 116.2	$ 92.4
Long-term debt -		
First mortgage bonds	869.8	901.2
Other long-term debt	651.4	665.0
Rate reduction bonds	743.9	783.3

Other long-term debt includes $238.7 million and $227.5 million of fees and interest due for spent nuclear fuel disposal costs at December 31, 2007 and 2006, respectively.

Other Financial Instruments: The carrying value of other financial instruments included in current assets and current liabilities, including investments in securitizable assets, approximates their fair value due to the short-term nature of these instruments.

7. Leases

CL&P has entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, and office space. In addition, CL&P incurs costs associated with leases entered into by NUSCO and RRR. These costs are included below in operating lease payments charged to expense and amounts capitalized as well as future operating lease payments from 2008 through 2012 and thereafter. 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 2007, $2.9 million in 2006 and $3 million in 2005. Interest included in capital lease rental payments was $1.8 million in 2007, $1.7 million in 2006 and $1.8 million in 2005. Capital lease asset amortization was $0.7 million in 2007 and 2006 and $0.6 million in 2005.

Operating lease rental payments charged to expense were $13.2 million in 2007, $17.3 million in 2006 and $14.3 million in 2005. The capitalized portion of operating lease payments was approximately $6.5 million for the year ended December 31, 2007 and $6.2 million for each of the years ended December 31, 2006 and 2005.

Future minimum rental payments excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, at December 31, 2007 are as follows:

(Millions of Dollars)	Capital Leases	Operating Leases
2008	$ 3.2	18.8
2009	3.5	17.2
2010	1.7	15.3
2011	1.7	12.0
2012	1.8	10.2
Thereafter	16.8	45.0
Future minimum lease payments	28.7	$ 118.5
Less amount representing interest	(15.1)	
Present value of future minimum lease payments	$ 13.6	

In 2007, 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 table above. See Note 5D, "Commitments and Contingencies - Long-Term Contractual Arrangements," for further information regarding these contracts.

8. Dividend Restrictions

The Federal Power Act limits the payment of dividends by CL&P to its retained earnings balance and certain state statutes may impose additional limitations on CL&P. CL&P also has a revolving credit agreement that imposes a leverage restriction tied to its ratio of consolidated total debt to total capitalization.

9. Accumulated Other Comprehensive Income/(Loss)

The accumulated balance for each other comprehensive income/(loss), net of tax, item is as follows:

(Millions of Dollars)	December 31, 2006	Current Period Change	December 31, 2007
Qualified cash flow hedging instruments	$ 4.5	$ (4.8)	$ (0.3)
Unrealized gains on securities	0.1	-	0.1
Accumulated other comprehensive income/(loss)	$ 4.6	$ (4.8)	$ (0.2)

(Millions of Dollars)	December 31, 2005	Current Period Change	December 31, 2006
Qualified cash flow hedging instruments	$ -	$ 4.5	$ 4.5
Unrealized gains on securities	0.1	-	0.1
Minimum SERP liability	(0.4)	0.4	-
Accumulated other comprehensive (loss)/income	$ (0.3)	$ 4.9	$ 4.6

The changes in the components of other comprehensive income/(loss) are reported net of the following income tax effects:

(Millions of Dollars)	2007	2006	2005
Qualified cash flow hedging instruments	$ 3.2	$ (3.1)	$ -
Unrealized gains on securities	-	-	-
Minimum SERP liability	-	(0.2)	(0.1)
Accumulated other comprehensive income/(loss)	$ 3.2	$ (3.3)	$ (0.1)

The unrealized gains on securities above relate to $2.4 million and $2.2 million of SERP securities at December 31, 2007 and 2006, respectively. The fair value of these securities is included in prepayments and other on the accompanying consolidated balance sheets.

Fair value adjustments included in accumulated other comprehensive income/(loss) for CL&P's qualified cash flow hedging instruments are as follows:

	At December 31,	
(Millions of Dollars, Net of Tax)	2007	2006
Balance at beginning of year	$ 4.5	$ -
Hedged transactions recognized into earnings	0.1	(0.1)
Cash flow transactions entered into for period	(4.9)	4.6
Net change associated with hedging transactions	(4.8)	4.5
Total fair value adjustments included in accumulated other comprehensive income	$ (0.3)	$ 4.5

For the years ended December 31, 2007 and 2006, $0.1 million in expense and $0.1 million in income, respectively, net of tax, was reclassified from accumulated other comprehensive income/(loss) into earnings in connection with the consummation of interest rate swap agreements and the amortization of existing interest rate hedges.

In December of 2007, CL&P entered into two forward interest rate swap agreements associated with its planned 2008 long-term debt issuances. As a result, a gain of $1.4 million, net of tax, was recorded in accumulated other comprehensive loss with a corresponding pre-tax offset to derivative assets for the fair value of the derivative instruments as of December 31, 2007. For further information, see Note 3, "Derivative Instruments," to the consolidated financial statements.

In July of 2007, CL&P entered into two forward interest rate swap agreements to hedge the interest rates associated with $50 million of its $100 million, 10-year fixed rate long-term debt issuance and with $50 million of its $100 million, 30-year fixed rate long-term debt issuance. Under the agreements, CL&P had a LIBOR swap rate of 5.718 percent for the 10-year hedge and 5.865 percent for the 30-year hedge, both based on the notional amounts of $50 million in long-term debt that was issued in July of 2007. On July 16, 2007, the hedge was settled and a net of tax charge of $4.7 million ($7.7 million pre-tax), was recorded in accumulated other comprehensive loss to be amortized into earnings over the terms of the long-term debt. In addition, a net of tax charge of $67 thousand ($110 thousand pre-tax) was recorded related to ineffectiveness incurred upon termination of the hedge.

In February of 2007, CL&P entered into two forward interest rate swap agreements to hedge the interest rates associated with $75 million of its $150 million, 10-year fixed rate long-term debt issuance and with $75 million of its $150 million, 30-year fixed rate long-term debt issuance. Under the agreements, CL&P had a LIBOR swap rate of 5.229 percent for the 10-year hedge and 5.369 percent for the 30-year hedge, both based on the notional amounts of $75 million in long-term debt that was issued in March of 2007. On March 27, 2007, the hedge was settled and a net of tax charge of $1.6 million ($2.6 million pre-tax), was recorded in accumulated other comprehensive loss to be amortized into earnings over the terms of the long-term debt.

In March of 2006, CL&P entered into a forward interest rate swap agreement to hedge the interest rate associated with $125 million of its planned $250 million, 30-year fixed rate long-term debt issuance. Under the agreement, CL&P had a LIBOR swap rate of 5.322 percent based on the notional amount of $125 million in long-term debt that was issued in June of 2006. On June 1, 2006, the hedged transaction was settled, and as a result $4.6 million, net of tax ($7.8 million pre-tax), was recorded in accumulated other comprehensive income to be amortized into earnings over the term of the long-term debt.

It is estimated that a charge of $0.2 million will be reclassified from accumulated other comprehensive loss as a decrease to earnings over the next 12 months as a result of amortization of the interest rate swap agreements which have been settled. This amount will be impacted by the settlement of forward interest rate swap agreements.

10. Preferred Stock Not Subject to Mandatory Redemption

CL&P's charter authorizes it to issue up to 9 million shares of preferred stock ($50 par value per share) of which 2,324,000 shares were outstanding at December 31, 2007 and 2006. In addition, CL&P's charter authorizes it to issue up to 8 million shares of Class A preferred stock ($25 par value per share). There were no Class A preferred shares outstanding at December 31, 2007 and 2006. The issuance of additional preferred shares would be subject to approval by the DPUC.

Preferred stockholders have liquidation rights equal to the par value for each class, which they would receive in preference to any distributions to any junior stock. Were there to be a shortfall, all preferred stockholders would share ratably in available liquidation assets. Details of preferred stock not subject to mandatory redemption are as follows (in millions except in redemption price and shares):

Description		December 31, 2007 Redemption Price	Shares Outstanding at December 31, 2007 and 2006	December 31, 2007	December 31, 2006
$1.90	Series of 1947	$52.50	163,912	$ 8.2	$ 8.2
$2.00	Series of 1947	54.00	336,088	16.8	16.8
$2.04	Series of 1949	52.00	100,000	5.0	5.0
$2.20	Series of 1949	52.50	200,000	10.0	10.0
3.90%	Series of 1949	50.50	160,000	8.0	8.0
$2.06	Series E of 1954	51.00	200,000	10.0	10.0
$2.09	Series F of 1955	51.00	100,000	5.0	5.0
4.50%	Series of 1956	50.75	104,000	5.2	5.2
4.96%	Series of 1958	50.50	100,000	5.0	5.0
4.50%	Series of 1963	50.50	160,000	8.0	8.0
5.28%	Series of 1967	51.43	200,000	10.0	10.0
$3.24	Series G of 1968	51.84	300,000	15.0	15.0
6.56%	Series of 1968	51.44	200,000	10.0	10.0
Totals			2,324,000	$ 116.2	$ 116.2

Dividends of $5.6 million were paid to the preferred stockholders in both 2007 and 2006.

11. Long-Term Debt

Details of long-term debt outstanding are as follows:

At December 31,	2007	2006
	(Millions of Dollars)	
First Mortgage Bonds:		
7.875% 1994 Series D due 2024	$ 139.8	$ 139.8
4.800% 2004 Series A due 2014	150.0	150.0
5.750% 2005 Series B due 2034	130.0	130.0
5.000% 2005 Series A due 2015	100.0	100.0
5.625% 2005 Series B due 2035	100.0	100.0
6.350% 2006 Series A due 2036	250.0	250.0
5.375% 2007 Series A due 2017	150.0	-
5.750% 2007 Series B due 2037	150.0	-
5.750% 2007 Series C due 2017	100.0	-
6.375% 2007 Series D due 2037	100.0	-
Total First Mortgage Bonds	1,369.8	869.8
Pollution Control Notes:		
5.85%-5.90%, fixed rate, due 2016-2022	46.4	46.4
5.85%-5.95%, fixed rate tax exempt, due 2028	315.5	315.5
Variable rate, tax exempt, due 2031	62.0	62.0
Total Pollution Control Notes	423.9	423.9
Total First Mortgage Bonds and Pollution Control Notes	1,793.7	1,293.7
Fees and interest due for spent nuclear fuel disposal costs	238.7	227.5
Less amounts due within one year	-	-
Unamortized premium and discount, net	(3.9)	(1.8)
Long-term debt	$ 2,028.5	$ 1,519.4

There are no cash sinking fund requirements or debt maturities for the years 2008 through 2012.

Essentially all utility plant of CL&P is subject to the liens of CL&P's first mortgage bond indenture.

CL&P has $315.5 million of tax-exempt Pollution Control Revenue Bonds (PCRBs) secured by second mortgage liens on transmission assets, junior to the liens of its first mortgage bond indentures.

CL&P has $62 million of tax-exempt PCRBs secured by bond insurance and first mortgage bonds. For financial reporting purposes, this debt is not considered to be first mortgage bonds unless CL&P fails to meet its obligations under the PCRBs. The CL&P pollution control note due in 2031 has an interest rate of 3.35 percent effective through October 1, 2008, at which time the bonds will be remarketed and the interest rate will be adjusted.

In 2007, CL&P issued $500 million of first mortgage bonds. The proceeds were used to refinance the company's short-term borrowings, which were previously incurred to fund transmission segment and distribution segment capital expenditures.

CL&P's long-term debt agreements provide that it must comply with certain financial and non-financial covenants as are customarily included in such agreements, including but not limited to, debt service coverage ratios and interest coverage ratios. CL&P currently is and expects to remain in compliance with these covenants.

For information regarding fees and interest due for spent nuclear fuel disposal costs, see Note 5C, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

12. Segment Information

Segment information related to the distribution and transmission businesses for CL&P for the years ended December 31, 2007, 2006 and 2005 is as follows:

	For the Year Ended December 31, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues (1)	$ 3,452.8	$ 229.0	$ 3,681.8
Depreciation and amortization	(279.5)	(29.0)	(308.5)
Other operating expenses	(3,004.7)	(84.1)	(3,088.8)
Operating income	168.6	115.9	284.5
Interest expense, net of AFUDC	(108.1)	(30.3)	(138.4)
Interest income	3.0	2.5	5.5
Other income, net	22.6	11.8	34.4
Income tax expense	(20.7)	(31.7)	(52.4)
Net income	$ 65.4	$ 68.2	$ 133.6
Total assets (2)	$ 7,018.1	$ -	$ 7,018.1
Cash flows for total investments in plant (3)	$ 242.3	$ 583.9	$ 826.2

	For the Year Ended December 31, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues (1)	$ 3,825.2	$ 154.6	$ 3,979.8
Depreciation and amortization	(241.0)	(22.1)	(263.1)
Other operating expenses	(3,416.3)	(64.3)	(3,480.6)
Operating income	167.9	68.2	236.1
Interest expense, net of AFUDC	(100.5)	(17.4)	(117.9)
Interest income	6.6	0.4	7.0
Other income, net	24.6	6.2	30.8
Income tax benefit/(expense)	53.3	(9.3)	44.0
Net income	$ 151.9	$ 48.1	$ 200.0
Total assets (2)	$ 6,321.3	$ -	$ 6,321.3
Cash flows for total investments in plant (3)	$ 183.8	$ 383.4	$ 567.2

	For the Year Ended December 31, 2005		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues (1)	$ 3,353.7	$ 112.7	$ 3,466.4
Depreciation and amortization	(293.5)	(17.7)	(311.2)
Other operating expenses	(2,899.1)	(54.1)	(2,953.2)
Operating income	161.1	40.9	202.0
Interest expense, net of AFUDC	(108.5)	(11.5)	(120.0)
Interest income	2.9	0.4	3.3
Other income, net	34.8	6.9	41.7
Income tax expense	(26.2)	(6.0)	(32.2)
Net income	$ 64.1	$ 30.7	$ 94.8
Cash flows for total investments in plant (3)	$ 236.6	$ 207.8	$ 444.4

(1) CL&P revenues are primarily derived from residential, commercial and industrial customers and are not dependent on any single customer.

(2) Information for segmenting total assets between distribution and transmission is not available at December 31, 2007 and 2006. The distribution and transmission assets are disclosed in the distribution columns above.

(3) Cash flows for total investments in plant included in the segment information above are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income.

Consolidated Quarterly Financial Data (Unaudited)

(Thousands of Dollars)	Quarter Ended March 31,	June 30,	September 30,	December 31,
2007				
Operating Revenues	$ 1,043,686	$ 870,379	$ 918,418	$ 849,334
Operating Income	78,964	63,951	71,423	70,204
Net Income	34,994	25,786	34,976	37,808
2006				
Operating Revenues	$ 1,004,760	$ 939,720	$ 1,083,299	$ 952,032
Operating Income	60,769	47,938	54,729	72,634
Net Income	33,830	17,472	101,033	47,672

Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2007	2006	2005	2004	2003
Operating Revenues	$ 3,681,817	$ 3,979,811	$ 3,466,420	$ 2,832,924	$ 2,704,524
Net Income	133,564	200,007	94,845	88,016	68,908
Dividends on Common Stock	79,181	63,732	53,834	47,074	60,110
Property, Plant and Equipment, net (a)	4,401,846	3,634,370	3,166,692	2,824,877	2,561,898
Total Assets	7,018,099	6,321,294	5,765,072	5,306,913	5,206,894
Rate Reduction Bonds	548,686	743,899	856,479	995,233	1,124,779
Long-Term Debt (b)	2,028,546	1,519,440	1,258,883	1,052,891	830,149
Preferred Stock - Non-Redeemable	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (b)	13,602	14,264	13,488	14,093	14,879

(a) Amount includes CWIP.

(b) Includes portions due within one year, but excludes rate reduction bonds.

During the fourth quarter of 2007, CL&P determined that there was an error in certain assumptions supporting the initial FIN 48 adoption amounts recorded in the first quarter of 2007. The correction of the error resulted in the increase of the initial retained earnings reduction amount from $15.6 million to $24 million. This correction of the initial FIN 48 adoption accounting, which also affected certain liability balances reported in prior interim periods, did not have an effect on the income tax provision for 2007 and did not have a material impact on CL&P's consolidated financial statements for the quarterly periods ending March 31, 2007, June 30, 2007 and September 30, 2007.

Selected Consolidated Sales Statistics
(Unaudited)

	2007	2006	2005	2004	2003
Revenues: *(Thousands)*					
Utility Group:					
Residential	$ 1,854,404	$ 1,709,700	$ 1,440,142	$ 1,155,492	$ 1,151,707
Commercial	1,182,196	1,405,281	1,170,038	939,579	960,678
Industrial	208,087	380,479	327,598	275,730	290,526
Other Utilities	347,514	318,958	344,650	295,833	322,955
Streetlighting and Railroads	35,370	42,099	37,054	31,897	35,358
Miscellaneous	54,246	123,294	146,938	134,393	(56,700)
Total	$ 3,681,817	$ 3,979,811	$ 3,466,420	$ 2,832,924	$ 2,704,524
Sales: *(KWH - Millions)*					
Residential	10,336	10,053	10,760	10,305	10,359
Commercial	10,128	9,995	10,307	9,922	9,829
Industrial	3,264	3,306	3,501	3,623	3,630
Other Utilities	3,563	3,749	4,179	5,375	5,885
Streetlighting and Railroads	304	284	298	298	298
Total	27,595	27,387	29,045	29,523	30,001
Customers: *(Average)*					
Residential	1,091,799	1,084,937	1,078,723	1,071,249	1,058,247
Commercial	102,411	101,563	108,558	108,865	104,750
Industrial	3,743	3,848	3,976	4,078	3,989
Other	2,583	2,592	2,630	2,694	2,643
Total	1,200,536	1,192,940	1,193,887	1,186,886	1,169,629

2007 Annual Report
Western Massachusetts Electric Company

Company Report

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the related notes included in this Annual Report. References in this exhibit to "WMECO" or "the company" are to Western Massachusetts Electric Company, and the terms "we," "us" and "our" refer to WMECO.

Overview

We are a wholly owned subsidiary of Northeast Utilities (NU). NU's other regulated electric subsidiaries include The Connecticut Light and Power Company and Public Service Company of New Hampshire.

We earned $23.6 million in 2007, compared with $15.6 million in 2006 and $15.1 million in 2005. Included in earnings were transmission segment earnings of $5.1 million, $4.6 million and $4 million in 2007, 2006 and 2005, respectively, and distribution segment earnings of $18.5 million, $11 million and $11.1 million in 2007, 2006 and 2005, respectively.

Our distribution segment earnings in 2007 were $7.5 million higher than in 2006 primarily due to the impacts of a rate settlement that became effective on January 1, 2007. The settlement included, among other things, a $1 million annualized rate increase and the implementation of several cost tracking mechanisms. The 2007 earnings also did not include certain charges that negatively impacted us in 2006. Higher earnings were partially offset by higher depreciation expense. Our distribution segment regulatory return on equity (Regulatory ROE) was approximately 9.7 percent in 2007 and 9.6 percent in 2006. We expect our distribution segment Regulatory ROE to be towards the low end of a 9 percent to 10 percent range at approximately 9 percent in 2008.

The increase in transmission segment earnings in 2007 was due to a higher level of investment in our transmission infrastructure.

For the distribution segment, a summary of changes in our retail electric kilowatt-hour (KWH) sales for 2007 as compared to 2006 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)
Residential	1.9 %	(0.3)%
Commercial	1.0 %	0.5 %
Industrial	(2.3)%	(2.4)%
Total	0.6 %	(0.4)%

Our electric sales per customer, adjusted for weather impacts, have been negatively affected by retail rate increases driven by the energy component of customer bills that began in early 2006. Although the longer-term trend in customer usage in our service territory when energy prices were stable had reflected a generally increasing use per customer, customers have responded to higher energy prices in recent years by using less electricity. Even though generation costs stabilized in 2007, residential use per customer on a weather normalized basis is lower than 2006 levels, reflecting continued conservation efforts. We cannot determine at this time whether these trends will continue or the effect they may have on our distribution segment earnings.

Liquidity

Net cash flows from operations increased by $21.2 million from $16.3 million in 2006 to $37.5 million in 2007. The increase in operating cash flows was primarily due to an increase in recoveries from ratepayers due in part to retail rate adjustments that were effective in January of 2007. In 2006, amortization of regulatory liabilities and regulatory overrecoveries represented a combined cash outflow of approximately $17 million due primarily to a decrease in the transition charge as overrecoveries were refunded to customers. In 2007, amortization of regulatory assets and regulatory overrecoveries represented a combined cash inflow of approximately $43 million due to retail transmission recoveries and other recoveries on tracked items. 2007 operating cash flows compared to 2006 also improved due to an approximately $9 million decrease in payments to the Yankee Companies for decommissioning costs. This incr ease was partially offset by the payment of $65.6 million in federal and state income taxes in 2007. We accrued the majority of our portion of this tax obligation in 2000 upon the sale of these generation assets to another NU subsidiary, but due to the intercompany nature of the sales, the federal and state income tax payments were deferred at that time. It was not until NU ultimately sold these generation assets to an unaffiliated third party in November of 2006 that we were required to pay this deferred tax obligation.

We, along with other NU subsidiaries, are a party to a five-year unsecured revolving credit facility which expires on November 6, 2010. We can borrow up to $100 million on a short-term basis, or subject to regulatory approvals, on a long-term basis. At December 31, 2007 and 2006, we had no borrowings outstanding under this facility.

In August of 2007, we issued $40 million of 30-year senior unsecured notes with a coupon rate of 6.7 percent and a maturity date of August 15, 2037. The proceeds were used to refinance our short term borrowings, which were previously incurred to fund transmission segment and distribution segment capital expenditures.

Our senior unsecured debt is rated Baa2, BBB and BBB+ with a stable outlook, by Moody's Investors Service, Standard & Poor's and Fitch Ratings, respectively. To ensure the consistency of these ratings, which aid in the achievement of competitive market rates for our debt issuances, we seek to maintain certain credit metrics satisfactory to the rating agencies, which include a target capitalization structure of approximately 55 percent debt and 45 percent equity. The three agencies each may include in the debt component of capitalization additional factors, such as the net present value of remaining operating leases and postretirement benefit obligations. Before the application of such adjustments, our ratio of consolidated total debt to total capitalization was approximately 52 percent as of December 31, 2007. We seek to maintain our target structure over the long term through a proper balance of c apital infusions from NU parent and new debt issuances or borrowings.

In 2007 and 2006, NU contributed equity to us of $13.6 million and $31.9 million, respectively. In general, we pay approximately 60 percent of our cash earnings to NU in the form of common dividends. In 2007 and 2006, we paid common dividends to NU of $12.8 million and $7.9 million, respectively.

Capital expenditures described herein are cash capital expenditures and do not include amounts incurred but not paid, cost of removal, the allowance for funds used during construction (AFUDC) related to equity funds, and the capitalized portion of pension expense or income. Our cash capital expenditures totaled $47.3 million in 2007, compared with $42.8 million in 2006 and $44.7 million in 2005.

Capital expenditures are expected to increase significantly over the next several years with the 115 kilovolt (KV) Springfield Underground Cables transmission project and our portion of the New England East-West 345 KV and 115 KV Overhead transmission projects. We project our capital expenditures to total approximately $825 million from 2008 to 2012, of which $648 million relates to our transmission segment. In order to finance this five-year capital program, we expect further debt issuances and equity infusions from NU parent as needed.

Regulatory Issue

On December 14, 2006, the Massachusetts Department of Public Utilities (formerly the Massachusetts Department of Telecommunications and Energy) (DPU) approved a rate case settlement agreement that included distribution rate increases of $1 million beginning on January 1, 2007 and an additional $3 million increase beginning on January 1, 2008. On January 1, 2008, WMECO adjusted its rates to include the distribution increase, new basic service contracts, and changes in several tracking mechanisms. The net impact of this rate adjustment is an average 6.2 percent increase in customers' total bills.

RESULTS OF OPERATIONS

The components of significant income statement variances for the past two years are provided in the table below.

Income Statement Variances	2007 over/(under) 2006		2006 over/(under) 2005	
(Millions of Dollars)	Amount	Percent	Amount	Percent
Operating Revenues	$ 33	8 %	$ 22	5 %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(44)	(16)	34	14
Other operation	17	21	10	15
Maintenance	3	18	-	-
Depreciation	4	21	1	6
Amortization of regulatory assets/(liabilities), net	38	(a)	(24)	(a)
Amortization of rate reduction bonds	1	7	1	7
Taxes other than income taxes	-	-	-	-
Total operating expenses	19	5	22	6
Operating Income	14	35	-	-
Interest expense, net	1	5	1	4
Other income, net	2	66	-	-
Income before income tax expense	15	63	(1)	(4)
Income tax expense	7	88	(2)	(16)
Net income	$ 8	51 %	$ 1	4 %

(a) Percent greater than 100.

Comparison of the Year 2007 to the Year 2006

Operating Revenues
Operating revenues increased $33 million compared to the same period in 2006 due to higher distribution segment revenue ($31 million) and higher transmission segment revenue ($3 million).

The distribution segment revenue increase of $31 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($27 million). See also amortization of regulatory assets/(liabilities), net below. The distribution revenue tracking components increase of $27 million is primarily due to higher retail transmission revenues ($25 million) and higher transition cost recoveries ($15 million), higher pension tracker and default service true-up revenues ($8 million) resulting from the distribution rate settlement that took effect January 1, 2007 and higher wholesale revenues ($3 million), partially offset by the pass through of lower energy supply costs ($25 million). The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected fr om customers in future periods.

The distribution component of revenues which impacts earnings increased $4 million primarily due to the distribution rate increase effective January 1, 2007 and higher retail sales. Retail sales increased 0.6 percent compared to the same period of 2006.

Transmission segment revenues increased $3 million primarily due to a higher transmission investment base and higher operating expenses, which are recovered under Federal Energy Regulatory Commission (FERC)-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power expense decreased $44 million primarily due to lower default service supply costs ($33 million) and lower purchased power costs ($10 million), which are included in a regulatory commission approved tracking mechanism. The default service supply costs are the contractual amounts we must pay to various suppliers that supply default service load after winning a competitive solicitation process. The decrease in these costs is primarily the result of decreased load levels resulting from customers migrating from default service to a third party energy supplier during 2007 as compared to 2006. Lower purchased power costs of $10 million are the result of lower capacity costs for the Yankee companies' contractual obligations as some of these companies complete decommissioning.

Other Operation
Other operation expenses increased $17 million primarily due to an increase in retail transmission expenses ($8 million), higher administrative expenses ($6 million) and higher uncollectible account expenses ($2 million). The increase in retail transmission expenses is mainly due to the deferral, resulting from the regulatory tracking mechanism as a result of the increase in retail transmission revenue rates.

Maintenance
Maintenance expense increased $3 million primarily due to higher tree trimming and maintenance of station equipment and structures expenses.

Depreciation
Depreciation expense increased $4 million primarily due to revised depreciation rates effective January 1, 2007 from the distribution rate settlement and higher utility plant balances.

Amortization of Regulatory Assets/(Liabilities), Net
Amortization of regulatory assets/(liabilities), net increased $38 million primarily due to the deferral of transition costs as a result of a higher transition charge rate and lower power contract net costs and the 2006 $18 million credit associated with the deferral of retail transmission costs.

Amortization of Rate Reduction Bonds
Amortization of rate reduction bonds increased $1 million. The higher portion of principal within the rate reduction bond's payment results in a corresponding increase in the amortization of regulatory assets.

Interest Expense, Net
Interest expense, net increased $1 million primarily due to higher interest on long-term debt as a result of the issuance of the sale of $40 million of unsecured notes in August 2007, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding.

Other Income, Net
Other income, net increased $2 million primarily due to higher investment income and higher equity of earnings as a result of regional nuclear generating companies.

Income Tax Expense
Income tax expense increased $7 million due to higher pre-tax earnings and a decrease in favorable tax adjustments.

Comparison of the Year 2006 to the Year 2005

Operating Revenues
Operating revenues increased $22 million compared to the same period in 2005, primarily due to higher distribution segment revenue ($20 million) and higher transmission segment revenue ($2 million).

The distribution segment revenue increase of $20 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($20 million). The distribution revenue tracking components increase of $20 million is primarily due to the pass through of higher energy supply costs ($28 million), partially offset by lower retail transmission revenues ($5 million) and lower wholesale revenues ($1 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 retail revenue which impacts earnings was flat as a result of the $3 million distribution rate increase that took affect January 1, 2006 being offset by a 4.2 percent decrease in sales.

Transmission segment revenues increased $2 million primarily due to a higher rate base and higher operating expenses which are recovered under the FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power expense increased $34 million primarily due to higher default service supply costs, which are included in a regulatory commission approved tracking mechanism. These default service supply costs are the contractual amounts we must pay to various suppliers that have earned the right to supply default service load through a competitive solicitation process. The increase in these costs is primarily the result of increases in the market price of electricity at the time of each solicitation.

Other Operation
Other operation expenses increased $10 million primarily due to higher reliability must run (RMR) costs ($14 million), which are included in a retail transmission regulatory rate tracking mechanism, and will be recovered from customers in future years, partially offset by lower pension and other benefit costs ($2 million) and lower conservation and load management expenses ($1 million).

Depreciation
Depreciation expense increased $1 million primarily due to higher utility plant balances.

Amortization of Regulatory Assets/(Liabilities), Net
Amortization of regulatory assets/(liabilities), net decreased $24 million primarily due to the deferral of retail transmission costs ($18 million), mainly as a result of higher RMR costs, and the deferral of higher transition costs ($5 million).

Amortization of Rate Reduction Bonds
Amortization of rate reduction bonds increased $1 million. The higher portion of principal within the rate reduction bond's payment results in a corresponding increase in the amortization of regulatory assets.

Interest Expense, Net
Interest expense, net increased $1 million primarily due to higher long-term debt levels as a result of the issuance of $50 million of ten-year senior notes in August of 2005 ($2 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($1 million).

Income Taxes
Income tax expense decreased $2 million due to lower pre-tax earnings and a decrease in the effective tax rate from 38.1 to 33.2 percent. The effective tax rate decrease primarily results from a deferred tax adjustment related to generation plants sold to an affiliate.

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 Western Massachusetts Electric Company and subsidiary (WMECO or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, WMECO conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that our internal controls over financial reporting were effective as of December 31, 2007.

February 28, 2008

Report of Independent Registered Public Accounting Firm

To the Board of Directors of
Western Massachusetts Electric Company:

We have audited the accompanying consolidated balance sheets of Western Massachusetts Electric Company and subsidiary (a Massachusetts corporation and a wholly owned subsidiary of Northeast Utilities) (the "Company") as of December 31, 2007 and 2006, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Western Massachusetts Electric Company and subsidiary as of December 31, 2007 and 2006, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1.G., the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, as of January 1, 2007.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
February 28, 2008

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

At December 31,	2007	2006
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 1,110	$ 1,336
Receivables, less provision for uncollectible accounts of $5,699 in 2007 and $5,073 in 2006	49,578	43,182
Accounts receivable from affiliated companies	258	5,628
Unbilled revenues	17,990	15,940
Taxes receivable	3,382	-
Materials and supplies	2,353	1,875
Marketable securities - current	31,286	28,054
Prepayments and other	2,661	1,080
	108,618	97,095
Property, Plant and Equipment:		
Electric utility	728,712	703,723
Less: Accumulated depreciation	205,743	201,099
	522,969	502,624
Construction work in progress	36,388	23,470
	559,357	526,094
Deferred Debits and Other Assets:		
Regulatory assets	193,921	252,346
Prepaid pension	90,015	69,933
Marketable securities - long-term	25,078	25,964
Other	14,099	17,261
	323,113	365,504
Total Assets	$ 991,088	$ 988,693

The accompanying notes are an integral part of these consolidated financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

At December 31,	2007	2006
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to affiliated companies	$ 14,900	$ 30,800
Accounts payable	30,636	28,008
Accounts payable to affiliated companies	7,480	4,184
Accrued taxes	633	27,615
Accrued interest	5,498	4,546
Other	9,856	9,273
	69,003	104,426
Rate Reduction Bonds	86,731	99,428
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	187,139	197,881
Accumulated deferred investment tax credits	2,015	2,319
Deferred contractual obligations	41,958	50,711
Regulatory liabilities	39,437	26,756
Accrued postretirement benefits	12,668	14,293
Other	5,015	12,136
	288,232	304,096
Capitalization:		
Long-Term Debt	303,872	261,777
Common Stockholder's Equity:		
Common stock, $25 par value - authorized 1,072,471 shares; 434,653 shares outstanding in 2007 and 2006	10,866	10,866
Capital surplus, paid in	128,228	114,544
Retained earnings	103,925	92,663
Accumulated other comprehensive income	231	893
Common Stockholder's Equity	243,250	218,966
Total Capitalization	547,122	480,743
Commitments and Contingencies (Note 4)		
Total Liabilities and Capitalization	$ 991,088	$ 988,693

The accompanying notes are an integral part of these consolidated financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2007	2006	2005
	(Thousands of Dollars)		
Operating Revenues	$ 464,745	$ 431,509	$ 409,393
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	236,582	280,158	245,763
Other	98,837	81,969	71,449
Maintenance	18,618	15,821	16,271
Depreciation	20,868	17,204	16,273
Amortization of regulatory assets/(liabilities), net	10,601	(27,516)	(3,518)
Amortization of rate reduction bonds	12,766	11,968	11,220
Taxes other than income taxes	12,322	11,932	11,661
Total operating expenses	410,594	391,536	369,119
Operating Income	54,151	39,973	40,274
Interest Expense:			
Interest on long-term debt	11,577	10,671	9,535
Interest on rate reduction bonds	5,839	6,723	7,570
Other interest	2,430	1,507	1,041
Interest expense, net	19,846	18,901	18,146
Other Income, Net	3,885	2,338	2,251
Income Before Income Tax Expense	38,190	23,410	24,379
Income Tax Expense	14,586	7,766	9,294
Net Income	$ 23,604	$ 15,644	$ 15,085
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME			
Net Income	$ 23,604	$ 15,644	$ 15,085
Other comprehensive (loss)/income, net of tax:			
Qualified cash flow hedging instruments	(704)	(99)	951
Unrealized gains/(losses) on securities	42	226	(244)
Minimum SERP liability	-	72	49
Other comprehensive (loss)/income, net of tax	(662)	199	756
Comprehensive Income	$ 22,942	$ 15,843	$ 15,841

The accompanying notes are an integral part of these consolidated financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock		Capital Surplus Paid In	Retained Earnings	Accumulated Other Comprehensive (Loss)/Income	Total
	Shares	Amount				
			(Thousands of Dollars, except share information)			
Balance at January 1, 2005	434,653	$ 10,866	$ 76,103	$ 77,565	$ (62)	$164,472
Net income for 2005				15,085		15,085
Dividends on common stock				(7,685)		(7,685)
Allocation of benefits - ESOP			(93)			(93)
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			28			28
Capital contribution from NU parent			6,773			6,773
Other comprehensive income					756	756
Balance at December 31, 2005	434,653	10,866	82,811	84,965	694	179,336
Net income for 2006				15,644		15,644
Dividends on common stock				(7,946)		(7,946)
Allocation of benefits - ESOP			(29)			(29)
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			(183)			(183)
Capital contribution from NU parent			31,945			31,945
Other comprehensive income					199	199
Balance at December 31, 2006	434,653	10,866	114,544	92,663	893	218,966
Adoption of FIN48 - accounting for uncertainty of income taxes				437		437
Net income for 2007				23,604		23,604
Dividends on common stock				(12,779)		(12,779)
Allocation of benefits - ESOP			77			77
Capital contribution from NU parent			13,607			13,607
Other comprehensive loss					(662)	(662)
Balance at December 31, 2007	434,653	$ 10,866	$ 128,228	$ 103,925	$ 231	$243,250

The accompanying notes are an integral part of these consolidated financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2007	2006	2005
		(Thousands of Dollars)	
Operating Activities:			
Net income	$ 23,604	$ 15,644	$ 15,085
Adjustments to reconcile to net cash flows provided by operating activities:			
Bad debt expense	6,922	5,503	3,857
Depreciation	20,868	17,204	16,273
Deferred income taxes	(15,332)	(17,192)	(1,884)
Amortization of regulatory assets/(liabilities), net	10,601	(27,516)	(3,518)
Amortization of rate reduction bonds	12,766	11,968	11,220
Pension income, net of capitalized portion	(3,066)	(803)	(647)
Regulatory overrecoveries	32,129	10,327	5,360
Deferred contractual obligations	(7,568)	(16,807)	(16,557)
Other non-cash adjustments	(283)	1,384	1,955
Other sources of cash	1,504	3,364	-
Other uses of cash	(1,010)	(122)	(6,029)
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(9,749)	(4,600)	(5,269)
Materials and supplies	(478)	(461)	74
Other current assets	(1,300)	(183)	130
Accounts payable	1,417	(7,544)	5,231
Taxes (receivable)/accrued	(35,014)	25,995	5,900
Other current liabilities	1,537	176	(1,150)
Net cash flows provided by operating activities	37,548	16,337	30,031
Investing Activities:			
Investments in property and plant	(47,315)	(42,818)	(44,739)
Proceeds from sales of investment securities	196,865	123,148	82,937
Purchases of investment securities	(199,803)	(125,782)	(84,939)
Net proceeds from sale of property	-	-	1,599
Other investing activities	929	2,637	1,504
Net cash flows used in investing activities	(49,324)	(42,815)	(43,638)
Financing Activities:			
Issuance of long-term debt	40,000	-	50,000
Retirement of rate reduction bonds	(12,697)	(11,903)	(11,158)
Decrease in short-term debt	-	-	(25,000)
(Decrease)/increase in NU Money Pool borrowings	(15,900)	15,900	(1,000)
Capital contributions from NU parent	13,607	31,945	6,773
Cash dividends on common stock	(12,779)	(7,946)	(7,685)
Other financing activities	(681)	(183)	-
Net cash flows provided by financing activities	11,550	27,813	11,930
Net (decrease)/increase in cash	(226)	1,335	(1,677)
Cash - beginning of year	1,336	1	1,678
Cash - end of year	$ 1,110	$ 1,336	$ 1
Supplemental Cash Flow Information:			
Cash paid/(received) during the year for:			
Interest, net of amounts capitalized	$ 20,259	$ 20,140	$ 17,900
Income taxes	$ 65,595	$ (677)	$ 5,084
Non-cash investing activities:			
Capital expenditures incurred but not paid	$ 6,593	$ 2,019	$ 2,865

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 Western Massachusetts Electric Company

Western Massachusetts Electric Company (WMECO or the company) is a wholly-owned subsidiary of Northeast Utilities (NU). WMECO is a reporting company under the Securities Exchange Act of 1934. Until February 8, 2006, NU was registered with the Securities and Exchange Commission 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 WMECO, 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. WMECO is subject to further regulation for rates, accounting and other matters by the FERC and the Massachusetts Department of Public Utilities (formerly the Departm ent of Telecommunications and Energy) (DPU). WMECO furnishes franchised retail electric service in Massachusetts. WMECO's results include the operations of its distribution and transmission segments.

Several wholly-owned subsidiaries of NU provide support services for NU's companies, including WMECO. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. Three other subsidiaries construct, acquire, or lease some of the property and facilities used by WMECO.

At December 31, 2007 and 2006, WMECO had a long-term receivable from NUSCO in the amount of $5.5 million that is included in deferred debits and other assets - other on the accompanying consolidated balance sheets related to the funding of investments held by NUSCO in connection with certain postretirement benefits for WMECO employees.

Included in the consolidated balance sheet at December 31, 2007 are accounts receivable from affiliated companies and accounts payable to affiliated companies totaling $0.3 million and $7.5 million, respectively, relating to transactions between WMECO and other subsidiaries that are wholly owned by NU. At December 31, 2006, these amounts totaled $5.6 million and $4.2 million, respectively.

Total WMECO purchases from Select Energy, Inc. (Select Energy), another NU subsidiary, were $0.9 million and $36.3 million for the years ended December 31, 2006 and 2005, respectively. There were no such purchases in 2007.

In 2007, WMECO made a discretionary contribution of $0.1 million to the NU Foundation, Inc. (Foundation), an independent not-for-profit charitable entity designed to invest in projects that emphasize economic development, workforce training and education, and a clean and healthy environment. The board of directors of the Foundation consists of certain NU officers. Any donations made to the Foundation negatively impact the earnings of WMECO.

B. Presentation

The consolidated financial statements of WMECO include the accounts of its subsidiary WMECO Funding LLC. 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.

C. Accounting Standards Issued But Not Yet Adopted

Fair Value Measurements: On September 15, 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is applicable to fair value measurements of derivative contracts that are subject to mark-to-market accounting and to other assets and liabilities that are reported at fair value or subject to fair value measurements. Management does not expect the adoptio n of SFAS No. 157 to have a material impact on WMECO's consolidated financial statements.

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 is effective in the first quarter of 2008, with the effect of application to eligible items as of January 1, 2008 required to be reflected as a cumulative-effect adjustment to the opening balance of retained earnings. If a company elects the fair value option for an eligible item, changes in that item's fair value at subsequent reporting dates must be recognized in earnings. Management is currently evaluating whether or not to elect the fair value option for WMECO's securities held in trust as of J anuary 1, 2008. Implementation of SFAS No. 159 for WMECO's securities held in trust is not expected to have a material effect on the consolidated financial statements.

D. Revenues

WMECO's retail revenues are based on rates approved by the DPU. In general, rates can only be changed through formal proceedings with the DPU. However, WMECO utilizes regulatory commission-approved tracking mechanisms to track the recovery of certain incurred costs. These tracking mechanisms allow for rates to be changed periodically, with overcollections refunded to customers or undercollections collected from customers in future periods.

Unbilled Revenues: Unbilled revenues represent an estimate of electricity 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 or under other circumstances.

WMECO estimates 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.

Transmission Revenues - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of NU's wholesale transmission revenues are collected under the New England Independent System Operator (ISO-NE) FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Local Network Service (LNS) rate schedules to recover transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users including WMECO's transmission business, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, administered by NU, is reset on January 1st and June 1st of each year and recovers the revenue requ irements for local transmission facilities and other transmission costs not recovered under the RNS rate. The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to retail customers. At December 31, 2007, the LNS rates for WMECO's transmission segment were in an underrecovery position of approximately $2 million, which will be recovered from LNS customers in mid-2008. WMECO believes that these rates will provide it with timely recovery of transmission costs, including costs of its major transmission projects.

Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution segments of WMECO and other NU companies, which recover these costs through rates charged to their retail customers. WMECO has a retail transmission cost tracking mechanism as part of its rates. This tracking mechanism allows WMECO to charge its retail customers for transmission charges on a timely basis. At December 31, 2007, WMECO had retail transmission overcollections of $5.8 million. At December 31, 2006, WMECO had retail transmission undercollections of $9.8 million, which reflected the netting of the $17.5 million transition charge overrecovery from WMECO's 2006 rate case settlement.

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. WMECO has energy contracts that qualify for the normal purchases and sales exception. Derivatives under the exception and non-derivative contracts are recorded under accrual accounting, and related revenues or costs are recorded at the time of delivery or settlement.

The judgment applied in the election of the normal purchases and sales exception (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting is terminated and fair value accounting is applied.

F. Regulatory Accounting

The accounting policies of WMECO 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 WMECO 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 WMECO will recover its investments in long-lived assets, including regulatory assets. Excluding the securitized regulatory asset amount, a substantial portion of the regulatory assets earn an equity return. 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 WMECO's regulatory assets are as follows:

	At December 31,	
(Millions of Dollars)	**2007**	**2006**
Securitized assets	$ 85.6	$ 98.3
Unrecovered contractual obligations	42.0	50.7
Income taxes, net	38.2	41.3
Recoverable nuclear costs	9.3	13.7
Deferred benefit costs	8.2	25.8
Other regulatory assets	10.6	22.5
Totals	$ 193.9	$ 252.3

Securitized Assets: In May 2001, WMECO issued $155 million in rate reduction certificates and used the majority of the proceeds from that issuance to buyout an Independent Power Producer (IPP) contract. The unamortized WMECO securitized asset balance was $85.6 million and $98.3 million at December 31, 2007 and 2006, respectively.

Securitized regulatory assets, which are not earning an equity return, are being recovered over the amortization period of their associated rate reduction certificates. All outstanding rate reduction certificates of WMECO are scheduled to fully amortize by June 1, 2013.

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), WMECO is responsible for its proportionate share of the remaining costs of the units, including decommissioning. Unrecovered contractual obligations of $42 million and $50.7 million were recorded at December 31, 2007 and 2006, respectively. WMECO amounts are being recovered along with other stranded costs.

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 DPU, SFAS No. 109 and FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." Differences in income taxes between SFAS No. 109, FIN 48 and the rate-making treatment of the DPU are recorded as regulatory assets which totaled $38.2 million and $41.3 million at December 31, 2007 and 2006, respectively. For further information regarding income taxes, see Note 1G, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial stateme nts.

Recoverable Nuclear Costs: Included in recoverable nuclear costs at December 31, 2007 and 2006 are $9.3 million and $13.7 million, respectively, of costs primarily related to Millstone 1 recoverable nuclear costs for the undepreciated plant and related assets at the time Millstone 1 was shutdown.

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, Supplemental Executive Retirement Plan (SERP), and postretirement benefits other than pension (PBOP) Plan, of which each includes eligible employees of WMECO, 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 WMECO is a cost-of-service, rate regulated entity under SFAS No. 71, offsets were recorded as a regulatory asset of $8.2 million at December 31, 2007 and $25.8 million at December 31, 2006 as these amounts have been and continue to be recoverable in cost-of-service, regulated rates. Regulat ory accounting was also applied to the portions of the NUSCO costs that support WMECO, as these amounts were also recoverable. The deferred benefit costs are included in rate base.

Other Regulatory Assets: Included in other regulatory assets are the regulatory assets associated with the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $2.7 million and $2.3 million at December 31, 2007 and 2006, respectively. As part of WMECO's rate case settlement, the DPU approved accounting requirements setting forth the recognition of its asset retirement obligations and a corresponding regulatory asset. Management believes that these regulatory assets are probable of recovery.

At December 31, 2007 and 2006, other regulatory assets also included $0.5 million and $0.6 million, respectively, related to losses on reacquired debt, $9.8 million at December 31, 2006 related to the undercollections of the retail transmission tracker, $2.6 million and $4.3 million, respectively, related to C&LM deferral, $1.3 million and $1.9 million, respectively, related to recoverable energy costs and $3.5 million and $3.6 million, respectively, related to various other items.

Regulatory Liabilities: The components of regulatory liabilities are as follows:

	At December 31,	
(Millions of Dollars)	**2007**	**2006**
Cost of removal	$ 21.5	$ 23.6
Transmission refunds	5.8	-
Pension/PBOP tracker	4.6	-
Default service overcollections	3.9	2.4
Other regulatory liabilities	3.6	0.8
Totals	$ 39.4	$ 26.8

Cost of Removal: WMECO currently recovers amounts in rates for future costs of removal of plant assets. These amounts, which totaled $21.5 million and $23.6 million at December 31, 2007 and 2006, respectively, are classified as regulatory liabilities on the accompanying consolidated balance sheets. These liabilities are included in rate base.

Transmission Refunds: Transmission refunds relate to the retail transmission tracker costs that WMECO incurred on behalf of its customers in the delivery of customer energy services and collected these costs in rates. At December 31, 2007, WMECO had overcollections of $5.8 million related to these transmission costs. At December 31, 2006, WMECO had undercollections of $9.8 million discussed in other regulatory assets above.

Pension/PBOP Tracker: In 2006, the DPU approved a cost tracking mechanism for WMECO's pension and PBOP plan costs effective on January 1, 2007. The approved tracking mechanism also allows WMECO to earn a return on its pension and PBOP assets and liabilities at its weighted average cost of capital, including the future pension and PBOP benefit obligations deferred under SFAS No. 158. At December 31, 2007, WMECO had overcollections of $4.6 million.

Default Service Overcollections: The default service rate allows WMECO to recover the costs of the procurement of energy for basic service, which includes forward capacity market charges. At December 31, 2007 and 2006, default service overcollections totaled $3.9 million and $2.4 million, respectively.

G. Income Taxes

The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the DPU, SFAS No. 109 and FIN 48. Details of income tax expense are as follows:

	For the Years Ended December 31,		
	2007	**2006**	**2005**
		(Millions of Dollars)	
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	$ 26.4	$ 25.5	$ 10.1
State	3.8	(0.2)	1.1
Total current	30.2	25.3	11.2
Deferred income taxes, net:			
Federal	(12.9)	(21.2)	(2.0)
State	(2.4)	4.0	0.4
Total deferred	(15.3)	(17.2)	(1.6)
Investment tax credits, net	(0.3)	(0.3)	(0.3)
Income tax expense	$ 14.6	$ 7.8	$ 9.3

A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:

	For the Years Ended December 31,		
	2007	2006	2005
	(Millions of Dollars, except percentages)		
Income before income tax expense	$ 38.2	$ 23.4	$ 24.4
Expected federal income tax expense	13.4	8.2	8.5
Tax effect of differences:			
Depreciation	0.5	(0.3)	0.4
Investment tax credit amortization	(0.3)	(0.3)	(0.3)
Deferred tax adjustment - sale to affiliate	-	(1.6)	-
State income taxes, net of federal impact	0.9	2.1	1.0
Medicare subsidy	(0.4)	(0.5)	(0.5)
Other, net	0.5	0.2	0.2
Income tax expense	$ 14.6	$ 7.8	$ 9.3
Effective tax rate	38.2 %	33.3 %	38.1 %

NU and its subsidiaries, including WMECO, file a consolidated federal income tax return and file state income tax returns. 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.

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)	2007	2006
Deferred tax liabilities - current:		
Property tax accruals and other	$ 2.3	$ 2.2
Total deferred tax liabilities - current	2.3	2.2
Deferred tax assets - current:		
Allowance for uncollectible accounts	2.2	2.0
Total deferred tax assets - current	2.2	2.0
Net deferred tax liabilities - current	0.1	0.2
Deferred tax liabilities - long-term:		
Accelerated depreciation and other plant-related differences	113.4	113.1
Employee benefits	33.5	27.0
Securitized costs	32.7	37.5
Income tax gross-up	17.8	19.7
Other	19.8	24.0
Total deferred tax liabilities - long-term	217.2	221.3
Deferred tax assets - long-term:		
Regulatory deferrals	16.9	6.8
Employee benefits	7.1	8.0
Income tax gross-up	2.8	3.4
ARO accounting	1.5	1.6
Other	1.8	3.6
Total deferred tax assets - long-term	30.1	23.4
Net deferred tax liabilities - long-term	187.1	197.9
Net deferred tax liabilities	$ 187.2	$ 198.1

Effective on January 1, 2007, WMECO 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, WMECO recorded estimates for uncertain tax positions in accordance with SFAS No. 5, "Accounting for Contingencies."

As a result of implementing FIN 48, WMECO recognized a cumulative effect of a change in accounting principle of $0.4 million as an increase to the January 1, 2007 balance of retained earnings.

Interest and Penalties: Effective on January 1, 2007, WMECO's accounting policy for the classification of interest and penalties related to FIN 48 is as follows:

- Interest on uncertain tax positions is recorded and classified as a component of other income, net. WMECO recorded accrued interest income of $0.9 million, which is included in the cumulative effect of a change in accounting principle, as of January 1, 2007. For the year ended December 31, 2007, WMECO recorded interest income of $1.4 million. At December 31, 2007, $2.3 million of accrued interest income was recognized on the accompanying consolidated balance sheet.

- No penalties have been recorded under FIN 48. If penalties are recorded in the future, then the estimated penalties would be classified as a component of other income/(loss), net.

Unrecognized Tax Benefits: WMECO did not have any unrecognized tax benefits upon the adoption of FIN 48 on January 1, 2007. As of December 31, 2007, WMECO's unrecognized tax benefit totaled $2.9 million, of which none would impact the effective tax rate, if recognized.

A reconciliation of the activity in unrecognized tax benefits from January 1, 2007 to December 31, 2007 is as follows:

(Millions of Dollars)	
Balance at beginning of year	$ -
Gross increases - prior year	2.9
Balance at end of year	$ 2.9

Tax Positions: NU is currently working to resolve all open tax years. It is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. Management estimates that potential resolutions could result in a zero to $2 million decrease in unrecognized tax benefits by WMECO. This estimated change is related to the timing of deducting expenses for book versus tax purposes, which is not expected to have a material impact on earnings.

Tax Years: The following table summarizes WMECO's tax years that remain subject to examination by major tax jurisdictions at December 31, 2007:

Description	Tax Years
Federal (NU consolidated)	2002 - 2007
Massachusetts	2004 - 2007

H. Property, Plant and Equipment and Depreciation

The following table summarizes WMECO's investments in utility plant at December 31, 2007and 2006 and the average depreciable life at December 31, 2007:

	Average Depreciable Life	At December 31, 2007	At December 31, 2006
	(Years)	*(Millions of Dollars)*	
Distribution	32.3	$ 596.3	$ 580.6
Transmission	52.3	132.4	123.1
Total property, plant and equipment		728.7	703.7
Less: Accumulated depreciation		(205.7)	(201.1)
Net property, plant and equipment		523.0	502.6
Construction work in progress		36.4	23.5
Total property, plant and equipment, net		$ 559.4	$ 526.1

The provision for depreciation on utility assets is calculated using the straight-line method based on estimated remaining useful lives of depreciable plant in-service, adjusted for salvage value and removal costs, as approved by the DPU. Depreciation rates are applied to plant-in-service from the time it is placed in service. When a plant is retired from service, the original cost of the plant is charged to the accumulated provision for depreciation which includes cost of removal less salvage. Cost of removal is classified as a regulatory liability. The depreciation rates for the several classes of utility plant-in-service are equivalent to a composite rate of 2.9 percent for 2007, and 2.5 percent for both 2006 and 2005.

I. Equity Method Investments

At December 31, 2007, WMECO owned common stock in three regional nuclear companies (Yankee Companies). Each of the Yankee Companies owned a single nuclear generating plant which has been decommissioned. WMECO's ownership interests in the Yankee Companies at December 31, 2007, which are accounted for on the equity method, were 9.5 percent of CYAPC, 7 percent of the YAEC, and 3 percent of the MYAPC. The total carrying value of WMECO's ownership interests in CYAPC, MYAPC and YAEC, which is included in deferred debits and other assets - other on the accompanying consolidated balance sheets and the distribution reportable segment, totaled $1.3 million and $1.8 million at December 31, 2007 and 2006, respectively. Earnings related to these equity investments are included in other income, net on the accompanying consolidated statements of income. For further information, see Note 1M, "Summary o f Significant Accounting Policies - Other Income, Net," to the consolidated financial statements.

For further information, see Note 4E, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements.

J. Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) is included in the cost of WMECO's utility plant and represents the cost of borrowed and equity funds used to finance construction. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of other interest expense, and the AFUDC related to equity funds is recorded as other income on the accompanying consolidated statements of income.

	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	**2007**	**2006**	**2005**
AFUDC:			
Borrowed funds	$ 1.0	$ 0.9	$ 0.5
Equity funds	0.2	0.2	0.2
Totals	$ 1.2	$ 1.1	$ 0.7
Average AFUDC rate	6.1 %	6.8 %	5.4 %

The average AFUDC rate is based on a FERC-prescribed formula that develops an average rate using the cost of the company's short-term financings as well as the company's capitalization (long-term debt and common equity). The average rate is applied to eligible construction work in progress (CWIP) amounts to calculate AFUDC.

K. Asset Retirement Obligations

WMECO implemented FIN 47 on December 31, 2005. FIN 47 requires an entity to recognize a liability for the fair value of an asset retirement obligation (ARO) on the obligation date if the liability's fair value can be reasonably estimated and is conditional on a future event. FIN 47 provides that settlement dates and future costs should be reasonably estimated when sufficient information becomes available and provides guidance on the definition and timing of sufficient information in determining expected cash flows and fair values. Management has identified various categories of AROs, primarily certain assets containing asbestos and hazardous contamination. A fair value calculation, reflecting expected probabilities for settlement scenarios, has been performed.

Because it is a cost-of-service, rate regulated entity, WMECO applies regulatory accounting in accordance with SFAS No. 71, and the costs associated with WMECO's AROs were included in other regulatory assets at December 31, 2007 and 2006.

The fair value of the AROs was recorded as a liability in deferred credits and other liabilities - other with an offset included in property, plant and equipment on the accompanying consolidated balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively. Both the depreciation and accretion were recorded as increases to regulatory assets on the accompanying consolidated balance sheets at December 31, 2007 and 2006.

The following tables present the ARO asset, the related accumulated depreciation, the regulatory asset, and the ARO liabilities at December 31, 2007 and 2006:

	At December 31, 2007			
(Millions of Dollars)	**ARO Asset**	**Accumulated Depreciation of ARO Asset**	**Regulatory Asset**	**ARO Liabilities**
Asbestos	$ 0.2	$ (0.1)	$ 1.5	$ (1.6)
Hazardous contamination	0.5	(0.1)	0.8	(1.2)
Other AROs	0.8	(0.3)	0.4	(0.9)
Total WMECO AROs	$ 1.5	$ (0.5)	$ 2.7	$ (3.7)

	At December 31, 2006			
(Millions of Dollars)	**ARO Asset**	**Accumulated Depreciation of ARO Asset**	**Regulatory Asset**	**ARO Liabilities**
Asbestos	$ 0.3	$ (0.2)	$ 1.4	$ (1.5)
Hazardous contamination	0.7	(0.1)	0.9	(1.5)
Other AROs	1.0	-	-	(1.0)
Total WMECO AROs	$ 2.0	$ (0.3)	$ 2.3	$ (4.0)

A reconciliation of the beginning and ending carrying amounts of WMECO's AROs is as follows:

(Millions of Dollars)	2007	2006
Balance at beginning of year	$ (4.0)	$ (3.2)
Liabilities incurred during the year	-	(1.0)
Liabilities settled during the year	0.2	-
Accretion	(0.1)	(0.1)
Change in estimates	0.5	0.4
Revisions in estimated cash flows	(0.3)	(0.1)
Balance at end of year	$ (3.7)	$ (4.0)

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.

L. Materials and Supplies

Materials and supplies include materials purchased primarily for construction, operation and maintenance (O&M) purposes. Materials and supplies are valued at the lower of average cost or market.

M. Other Income, Net

The pre-tax components of WMECO's other income/(loss) items are as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2007	2006	2005
Other Income:			
Investment income	$ 2.7	$ 1.4	$ 0.7
AFUDC - equity funds	0.2	0.2	0.2
Equity in earnings of regional nuclear generating companies	0.5	(0.2)	0.3
Conservation and load management incentive	0.5	0.9	0.9
Other	-	-	0.2
Total Other Income, Net	$ 3.9	$ 2.3	$ 2.3

Equity in earnings of regional nuclear generating companies relates to WMECO's investment in the Yankee Companies.

N. Marketable Securities

WMECO currently maintains a trust that holds marketable securities. The trust is used to fund WMECO's prior period spent nuclear fuel liability. In addition, WMECO owns marketable securities which are held to fund NU's SERP. WMECO's marketable securities are classified as available-for-sale, as defined by SFAS No. 115, "Accounting for Certain Investments and Debt and Equity Securities." At December 31, 2007, changes in the fair value of securities in the SERP trust relating to unrealized losses are considered other than temporary in nature and have been recorded as a pre-tax loss. Changes related to unrealized gains are recorded in accumulated other comprehensive income. Realized gains and losses and unrealized losses related to the SERP assets are included in other income, net on the consolidated statements of income. Realized gains, net of realized and unr ealized losses, associated with the WMECO spent nuclear fuel trust are recorded as an offset to the spent nuclear fuel trust obligation.

For information regarding marketable securities, see Note 6, "Marketable Securities," to the consolidated financial statements.

O. Provision for Uncollectible Accounts

WMECO 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.

P. Special Deposits

WMECO had amounts on deposit related to WMECO Funding LLC, a special purpose entity used to facilitate the issuance of rate reduction certificates. These amounts, which totaled $4.8 million and $4.7 million at December 31, 2007 and 2006, respectively, are included in deferred debits and other assets - other on the accompanying consolidated balance sheets.

2. Short-Term Debt

Limits: The amount of short-term borrowings that may be incurred by WMECO is subject to periodic approval by either the FERC or the DPU. On December 12, 2007, the FERC granted authorization to allow WMECO to incur total short-term borrowings up to a maximum of $200 million effective from December 31, 2007 through December 31, 2009.

Credit Agreement: WMECO, along with other NU subsidiaries, is a party to a five-year unsecured revolving credit facility which expires on November 6, 2010. WMECO is able to draw up to $100 million on a short-term basis, or subject to regulatory approvals, on a long-term basis. At December 31, 2007 and 2006, WMECO had no borrowings outstanding under this facility.

Pool: WMECO is a member of the NU Money Pool (Pool). The Pool provides an efficient use of cash resources at NU and reduces outside short-term borrowings. NUSCO administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are first met with available funds of other member companies, including funds borrowed by NU. NU may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on external loans by NU, however, bear interest at NU's cost and must be repaid based upon the terms of NU's original borrowing. At December 31, 2007 and 2006, WMECO had borrowings of $14.9 million and $30.8 million from the Pool, respectively. The weighted average i nterest rate on borrowings from the Pool for the years ended December 31, 2007 and 2006 was 5.16 percent and 5.01 percent, respectively.

3. Employee Benefits

A. Pension Benefits and Postretirement Benefits Other Than Pensions

On December 31, 2006, WMECO implemented SFAS No. 158, which applies to NU's Pension Plan, SERP, and PBOP Plan and required WMECO to record the funded status of these plans based on the projected benefit obligation for the Pension Plan and accumulated postretirement benefit obligation (APBO) for the PBOP Plan on the consolidated balance sheets at December 31, 2007 and 2006. SFAS No. 158 requires the additional liability to be recorded with an offset to accumulated other comprehensive income in common stockholders' equity. This amount is remeasured annually, or as circumstances dictate. However, because WMECO is a cost-of-service, rate regulated entity under SFAS No. 71, regulatory assets were recorded in the amount of $8.2 million and $25.8 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 WMECO, as these amounts are also recoverable.

Pension Benefits: WMECO participates in a uniform non-contributory defined benefit retirement plan (Pension Plan) covering substantially all regular WMECO employees. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. WMECO uses a December 31st measurement date for the Pension Plan. Pension income affecting earnings is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2007**	**2006**	**2005**
Total pension income	$ (5.0)	$ (1.3)	$ (0.9)
Income capitalized as utility plant	1.9	0.5	0.3
Total pension income, net of amounts capitalized	$ (3.1)	$ (0.8)	$ (0.6)

Total pension income above includes pension curtailments and termination benefits of $0.4 million in 2006, and an expense of $0.7 million in 2005. There were no pension curtailments or termination benefits in 2007.

Pension Curtailments and Termination Benefits: In December of 2005, a new program was approved allowing then current employees to elect to receive retirement benefits under a new 401(k) benefit rather than under the Pension Plan. The approval of the new plan resulted in recording an estimated pre-capitalization, pre-tax curtailment expense of $0.2 million in 2005, as a certain number of employees were expected to elect the new 401(k) benefit, resulting in a reduction in aggregate estimated future years of service under the Pension Plan. Because the predicted level of elections of the new benefit did not occur, WMECO recorded a pre-capitalization, pre-tax reduction in the curtailment expense of $0.1 million in 2006.

As a result of its corporate reorganization in 2005, WMECO recorded a combined pre-capitalization, pre-tax curtailment expense and related termination benefits for the Pension Plan totaling $0.5 million. Based on a revised estimate of expected head count reductions in 2006, WMECO recorded an adjustment to the curtailment and related termination benefits. This adjustment resulted in a pre-capitalization, pre-tax reduction in the curtailment expense and termination benefits of $0.3 million.

Pension Plan Cost of Living Adjustment: 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 $3.6 million and was reflected as a prior service cost and as a decrease in the funded status of the Pension Plan. This amount will be amortized over a 12-year period representing average remaining service lives of employees.

Market-Related Value of Pension Plan Assets: WMECO bases the actuarial determination of pension plan income or expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets and are included in actuarial gains and losses. Since the market-related valuation calculation recognizes gains or losses over a four-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

SERP: NU has maintained a SERP since 1987. The SERP provides its eligible participants, some of which are officers of WMECO, 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.

PBOP: WMECO provides certain health care benefits, primarily medical and dental, and life insurance benefits through a PBOP Plan. These benefits are available for employees retiring from WMECO 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. WMECO uses a December 31st measurement date for the PBOP Plan.

WMECO annually funds postretirement costs through external trusts with amounts that have been and will continue to be recovered in rates and that are tax deductible. Currently, there are no pending regulatory actions regarding postretirement benefit costs.

PBOP Curtailments and Termination Benefits: WMECO recorded an estimated $0.6 million pre-tax curtailment expense at December 31, 2005 relating to its corporate reorganization. WMECO also accrued a $0.1 million pre-tax termination benefit expense at December 31, 2005 relating to certain benefits provided under the terms of the PBOP Plan. Based on refinements to its estimates, WMECO 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 $0.3 million in 2006. There were no curtailments or termination benefits in 2007.

The following table represents information on the plans' benefit obligations, fair values of plan assets, and funded status:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Change in benefit obligation						
Benefit obligation at beginning of year	$ (172.9)	$ (171.7)	$ (0.6)	$ (0.6)	$ (40.7)	$ (42.9)
Service cost	(3.2)	(3.4)	-	-	(0.5)	(0.6)
Interest cost	(9.8)	(9.6)	-	-	(2.2)	(2.4)
Prior service cost	(3.6)	-	-	-	-	-
Actuarial gain	16.4	4.2	-	-	-	2.0
Transfers	-	-	-	-	-	0.5
Federal subsidy on benefits paid	-	-	-	-	(0.3)	(0.3)
Benefits paid - excluding lump sum payments	9.6	9.0	-	-	3.8	3.1
Curtailment/impact of plan changes	-	(1.6)	-	-	-	(0.1)
Termination benefits	-	0.2	-	-	-	-
Benefit obligation at end of year	$ (163.5)	$ (172.9)	$ (0.6)	$ (0.6)	$ (39.9)	$ (40.7)
Change in plan assets						
Fair value of plan assets at beginning of year	$ 242.8	$ 216.2	N/A	N/A	$ 26.4	$ 22.2
Actual return on plan assets	20.3	35.6	N/A	N/A	1.5	3.3
Employer contribution	-	-	N/A	N/A	3.1	4.3
Transfers	-	-	N/A	N/A	-	(0.3)
Benefits paid - excluding lump sum payments	(9.6)	(9.0)	N/A	N/A	(3.8)	(3.1)
Fair value of plan assets at end of year	$ 253.5	$ 242.8	N/A	N/A	$ 27.2	$ 26.4
Funded status at December 31st	$ 90.0	$ 69.9	$ (0.6)	$ (0.6)	$ (12.7)	$ (14.3)

The amounts recognized on the accompanying consolidated balance sheets for the funded status above at December 31, 2007 and 2006 is as follows:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Prepaid pension	$ 90.0	$ 69.9	$ -	$ -	$ -	$ -
Other deferred credits and other liabilities	-	-	(0.6)	(0.6)	-	-
Accrued postretirement benefits	-	-	-	-	(12.7)	(14.3)

In 2005, as a result of the expected transition of employees into the new 401(k) benefit and the company's corporate reorganization, NU reduced WMECO's share of the Pension Plan's obligation via a curtailment benefit related to the reduction in the future years of service expected to be rendered by plan participants. This overall reduction in plan obligation served to reduce the previously unrecognized actuarial losses. In 2006, $1.6 million of this curtailment was reversed because actual levels of elections of the new 401(k) benefit were much lower than expected and is reflected above as an increase to the obligation.

For the Pension Plan, the company amortizes its transition obligation over the remaining service lives of its employees as calculated for WMECO on an individual subsidiary basis and amortizes the prior service cost and unrecognized net actuarial loss over the remaining service lives of its employees as calculated on an NU consolidated basis. For the PBOP Plan, the company amortizes its transition obligation, prior service cost, and unrecognized net actuarial loss over the remaining service lives of its employees as calculated for WMECO on an individual subsidiary basis.

Although the SERP does not have any plan assets, benefit payments are supported by earnings on marketable securities held by NU.

The accumulated benefit obligation for the Pension Plan was $145.3 million and $155.3 million at December 31, 2007 and 2006, respectively, and $0.6 million for the SERP at December 31, 2007 and 2006.

The following is a summary of amounts recorded as regulatory assets as a result of SFAS No. 158 at December 31, 2007 and 2006 and the changes in those amounts recorded during the years (millions of dollars):

	At December 31,					
	Pension		SERP		PBOP	
	2007	2006	2007	2006	2007	2006
Transition obligation at beginning of year	$ -	$ -	$ -	$ -	$ 8.1	$ -
Amounts recorded upon adoption of SFAS No. 158	-	-	-	-	-	8.1
Amounts reclassified as net periodic benefit expense	-	-	-	-	(1.4)	-
Transition obligation at end of year	$ -	$ -	$ -	$ -	$ 6.7	$ 8.1
Prior service cost at beginning of year	$ 3.5	$ -	$ -	$ -	$ -	$ -
Amounts reclassified as net periodic benefit expense	(0.9)	-	-	-	-	-
Prior service cost arising during the year (1)	3.6	3.5	-	-	-	-
Prior service cost at end of year	$ 6.2	$ 3.5	$ -	$ -	$ -	$ -
Net actuarial losses at beginning of year	$ 8.5	$ -	$ 0.2	$ -	$ 5.5	$ -
Amounts reclassified as net periodic benefit expense	(1.1)	-	-	-	(0.7)	-
Actuarial (gains)/losses arising during the year (1)	(16.7)	8.5	(0.1)	0.2	(0.3)	5.5
Actuarial (gains)/losses at end of year	$ (9.3)	$ 8.5	$ 0.1	$ 0.2	$ 4.5	$ 5.5
Total deferred benefit costs as regulatory assets	$ (3.1)	$ 12.0	$ 0.1	$ 0.2	$ 11.2	$ 13.6

(1) Amounts arising for prior service cost and actuarial (gains)/losses in 2006 relate to the initial adoption of SFAS No. 158.

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2008 are as follows (millions of dollars):

	Estimated Expense in 2008		
	Pension	SERP	PBOP
Transition obligation	$ -	$ -	$ 1.3
Prior service cost	0.9	-	-
Net actuarial loss	0.1	-	0.6
Total	$ 1.0	$ -	$ 1.9

The following actuarial assumptions were used in calculating the plans' year end funded status:

	At December 31,			
	Pension Benefits and SERP		Postretirement Benefits	
Balance Sheets	2007	2006	2007	2006
Discount rate	6.6 %	5.90 %	6.35 %	5.80 %
Compensation/progression rate	4.0 %	4.00 %	N/A	N/A
Health care cost trend rate	N/A	N/A	8.50 %	9.00 %

The components of net periodic benefit expense are as follows:

	For the Years Ended December 31,								
	Pension Benefits			SERP Benefits			Postretirement Benefits		
(Millions of Dollars)	2007	2006	2005	2007	2006	2005	2007	2006	2005
Service cost	$ 3.2	$ 3.4	$ 3.4	$ -	$ -	$ -	$ 0.5	$ 0.6	$ 0.6
Interest cost	9.8	9.6	9.3	0.1	0.1	0.1	2.2	2.4	2.2
Expected return on plan assets	(20.0)	(17.8)	(17.4)	-	-	-	(1.8)	(1.4)	(1.3)
Net transition obligation cost	-	-	-	-	-	-	1.4	1.3	1.4
Prior service cost	0.9	0.7	0.7	-	-	-	-	-	-
Actuarial loss	1.1	3.2	2.4	-	-	-	0.7	1.5	-
Other amortization, net	-	-	-	-	-	-	-	-	1.3
Net periodic (income)/expense - before curtailments and termination benefits	(5.0)	(0.9)	(1.6)	0.1	0.1	0.1	3.0	4.4	4.2
Curtailment (benefits)/expense	-	(0.2)	0.4	-	-	-	-	(0.3)	0.6
Termination (benefits)/expense	-	(0.2)	0.3	-	-	-	-	-	0.1
Total curtailments and termination (benefits)/expense	- -	(0.4)	0.7	- -	- -	- -	- -	(0.3)	0.7
Total - net periodic (income)/expense	$ (5.0)	$ (1.3)	$ (0.9)	$ 0.1	$ 0.1	$ 0.1	$ 3.0	$ 4.1	$ 4.9

Not included in the pension (income)/expense amount above are pension related intercompany allocations totaling $1.6 million, $1.9 million, and $1.7 million for the years ended December 31, 2007, 2006 and 2005, respectively, including curtailment and termination benefits income of $0.2 million, and expense of $0.4 million for the years ended December 31, 2006 and 2005, respectively. Excluded from postretirement benefits expense are related intercompany allocations of $1.2 million, $1.2 million, and $1.4 million for the years ended December 31, 2007, 2006 and 2005, respectively, including curtailments and termination benefits income of $0.1 million and expense of $0.1 million, for the years ended December 31, 2006 and 2005, respectively. Excluded from SERP expense are related intercompany allocations of $0.3 million for the years ended December 31, 2007, 2006 and 2005. These amounts are included in other ope rating expenses on the accompanying consolidated statements of income.

The following assumptions were used to calculate pension and postretirement benefit expense and income amounts:

	For the Years Ended December 31,					
Statements of Income	Pension Benefits and SERP			Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
Discount rate	5.95 % (1)	5.80 %	6.00 %	5.80 %	5.65 %	5.50 %
Expected long-term rate of return	8.75 %	8.75 %	8.75 %	N/A	N/A	N/A
Compensation/progression rate	4.00 %	4.00 %	4.00 %	N/A	N/A	N/A
Expected long-term rate of return -						
Health assets, net of tax	N/A	N/A	N/A	6.85 %	6.85 %	6.85 %
Life assets and non-taxable health assets	N/A	N/A	N/A	8.75 %	8.75 %	8.75 %

(1) The 2007 discount rate for the SERP was 5.9 percent.

The following table represents the PBOP assumed health care cost trend rate for the next year and the assumed ultimate trend rate:

	Year Following December 31,	
	2007	2006
Health care cost trend rate assumed for next year	8.50 %	9.00 %
Rate to which health care cost trend rate is assumed to decline (the ultimate trend rate)	5.00 %	5.00 %
Year that the rate reaches the ultimate trend rate	2015	2011

At December 31, 2007, the health care cost trend assumption was reset for 2008 at 8.5 percent, decreasing one half percentage point per year to an ultimate rate of 5 percent in 2015.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point in each year would have the following effects:

(Millions of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Effect on total service and interest cost components	$ 0.1	$ (0.1)
Effect on postretirement benefit obligation	$ 1.3	$ (1.1)

NU's investment strategy for its Pension Plan and PBOP Plan is to maximize the long-term rate of return on those plans' assets within an acceptable level of risk. The investment strategy establishes target allocations, which are routinely reviewed and periodically rebalanced. NU's expected long-term rates of return on Pension Plan assets and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, NU also evaluated input from actuaries and consultants, as well as long-term inflation

assumptions and NU's historical 25-year compounded return of approximately 11.8 percent. The Pension Plan's and PBOP Plan's target asset allocation assumptions and expected long-term rate of return assumptions by asset category are as follows:

	At December 31,					
	Pension Benefits				Postretirement Benefits	
	2007		2006		2007 and 2006	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:						
United States	40%	9.25%	45%	9.25%	55%	9.25%
Non-United States	17%	9.25%	14%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	3%	10.25%	2%	10.25%
Private	8%	14.25%	8%	14.25%	-	-
Debt Securities:						
Fixed income	25%	5.50%	20%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%	5%	7.50%
Real Estate	5%	7.50%	5%	7.50%	-	-

The actual asset allocations at December 31, 2007 and 2006 approximated these target asset allocations. The plans' actual weighted-average asset allocations by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
Asset Category	2007	2006	2007	2006
Equity Securities:				
United States	40%	46%	55%	54%
Non-United States	17%	16%	14%	14%
Emerging markets	5%	4%	1%	1%
Private	7%	5%	-	-
Debt Securities:				
Fixed income	26%	19%	29%	29%
High yield fixed income	-	5%	1%	2%
Real Estate	5%	5%	-	-
Totals	100%	100%	100%	100%

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid/(received) for the Pension and PBOP plans:

(Millions of Dollars)

Year	Pension Benefits	SERP Benefits	Postretirement Benefits	Government Benefits
2008	$ 9.9	$ -	$ 4.1	$ (0.4)
2009	10.5	-	4.1	(0.4)
2010	10.8	-	4.1	(0.4)
2011	11.1	-	4.2	(0.4)
2012	11.5	-	4.1	(0.4)
2013-2017	64.0	0.3	19.8	(2.5)

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, WMECO's policy is to annually fund the Pension Plan in an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code. WMECO does not expect to make any contributions to the Pension Plan in 2008. For the PBOP Plan, it is currently WMECO's policy to annually fund an amount equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits. WMECO contributed $2.9 million for the year ended December 31, 2007 to fund the PBOP Plan and expects to make $2.9 million in contributions to the PBOP Plan in 2008. Beginning in 2007, NU made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $0.2 million in 2007 and is estimated to be $0.4 million in 2008.

B. Defined Contribution Plans

NU maintains a 401(k) Savings Plan for substantially all WMECO employees. This savings plan provides for employee contributions up to specified limits. NU matches employee contributions up to a maximum of three percent of eligible compensation with one percent in cash and two percent in NU common shares. The 401(k) matching contributions of cash and NU common shares made by NU to WMECO employees were $0.7 million in both 2007, 2006 and 2005, respectively.

Effective on January 1, 2006, all newly hired, non-bargaining unit employees of WMECO participate in a new defined contribution savings plan called the K-Vantage benefit. These employees are not eligible to participate in the existing defined benefit Pension

Plan. In addition, participants in the Pension Plan at January 1, 2006 were given the opportunity to choose to become a participant in the K-Vantage benefit beginning in 2007, in which case their benefit under the Pension Plan would be frozen. NU makes contributions to the K-Vantage benefit based on a percentage of participants' eligible compensation, as defined by the benefit document. The contributions made by NU to WMECO employees were $9 thousand and $2 thousand in 2007 and 2006, respectively.

C. Share-Based Payments

NU maintains an Employee Stock Purchase Plan (ESPP) and other long-term equity-based incentive plans under the Northeast Utilities Incentive Plan (Incentive Plan) in which WMECO employees and officers are entitled to participate. WMECO records compensation cost related to these plans, as applicable, for shares issued or sold to WMECO employees and officers, as well as the allocation of costs associated with shares issued or sold to NUSCO employees and officers that support WMECO. 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 WMECO's net income.

SFAS No. 123(R) requires that share-based payments be recorded using the fair value-based method based on the fair value at the date of grant and applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed. For prior periods, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," and related guidance, NU used the intrinsic value method and disclosed the pro forma effects as if NU recorded equity-based compensation under the fair value-based method.

Under SFAS No. 123(R), NU accounts for its various share-based plans as follows:

- For grants of restricted shares and restricted share units (RSUs), NU records compensation expense over the vesting period based upon the fair value of NU's common shares at the date of grant but records this expense net of estimated forfeitures.
- Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.
- NU has not granted any stock options to WMECO employees or officers 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 in which WMECO participates, NU is authorized to grant up to 4.5 million new shares for various types of awards, including restricted shares, RSUs, performance units and stock options to eligible employees and board members. At December 31, 2007 and 2006, NU had 3,055,083 and 570,494 of common shares, respectively, available for issuance under the Incentive Plan.

Restricted Shares and RSUs: NU has granted restricted shares under the 2002 through 2004 incentive programs that are subject to three-year and four-year graded vesting schedules. NU has granted RSUs under the 2004 through 2007 incentive programs that are subject to three-year and four-year graded vesting schedules. RSUs are paid in shares, including amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of total NU restricted share and RSU transactions for the year ended December 31, 2007 is as follows:

Restricted Shares	Restricted Shares	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	65,674	$15.00			
Granted	-	-			
Vested	(59,424)	$14.14	$0.8		
Outstanding at December 31, 2007	6,250	$18.65	$0.1	$ -	0.2

The per share and total weighted average grant date fair value for restricted shares vested was $14.52 and $1.1 million, respectively, for the year ended December 31, 2006 and $14.60 and $1.4 million, respectively, for the year ended December 31, 2005.

The total compensation cost recognized by WMECO for its portion of the restricted shares above was approximately $6 thousand, net of taxes of approximately $4 thousand for the year ended December 31, 2007, approximately $55 thousand, net of taxes of approximately $37 thousand for the year ended December 31, 2006 and approximately $63 thousand, net of taxes of approximately $42 thousand for the year ended December 31, 2005.

RSUs	RSUs (Units)	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	715,299	$19.41			
Granted	330,785	$28.83	$ 9.5		
Issued	(161,137)	$19.77	$ 3.2		
Forfeited	(53,947)	$20.16	$ 1.1		
Outstanding at December 31, 2007	831,000	$22.99	$19.1	$7.7	1.8

The per share and total weighted average grant date fair value for RSUs granted was $19.87 and $7.4 million, respectively, for the year ended December 31, 2006 and $18.89 and $5.8 million, respectively, for the year ended December 31, 2005. The weighted average grant date fair value per share for RSUs issued was $18.50 and $19.06 for the years ended December 31, 2006 and 2005, respectively. The total weighted average fair value of RSUs issued was $2.2 million and $1.9 million for the years ended December 31, 2006 and 2005, respectively.

The compensation cost recognized by WMECO for its portion of the RSUs above was approximately $387 thousand, net of taxes of approximately $258 thousand for the year ended December 31, 2007, approximately $271 thousand, net of taxes of approximately $181 thousand for the year ended December 31, 2006, and approximately $152 thousand, net of taxes of approximately $102 thousand for the year ended December 31, 2005.

Stock Options: Prior to 2003, NU granted stock options to certain WMECO employees. These options were fully vested as of December 31, 2005, and no compensation expense was recorded as a result of the adoption of SFAS No. 123(R). The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model.

4. Commitments and Contingencies

A. Regulatory Development

Transition Cost Reconciliations: WMECO filed its 2005 transition cost reconciliation with the DPU on March 31, 2006 and filed its 2006 transition cost reconciliation with the DPU on March 31, 2007. The DPU opened a proceeding for these filings, and evidentiary hearings were held on August 29, 2007. The briefing process was completed during October of 2007. The timing of the decision in this docket is uncertain. Management does not expect the outcome of the DPU's review of these filings to have a material adverse impact on WMECO's net income, financial position or cash flows.

B. Environmental Matters

General: WMECO 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, WMECO 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 WMECO's responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

The amounts recorded as environmental liabilities on the consolidated balance sheets represent management’s best estimate of the liability for environmental costs, if reasonably estimable, and take into consideration site assessment and remediation costs. Based on currently available information for estimated site assessment and remediation costs at December 31, 2007 and 2006, WMECO had $0.3 million for both years recorded as environmental reserves. A reconciliation of the activity in these reserves at December 31, 2007 and 2006 is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2007	2006
Balance at beginning of year	$ 0.3	$ 0.4
Additions and adjustments	0.3	0.3
Payments and adjustments	(0.3)	(0.4)
Balance at end of year	$ 0.3	$ 0.3

Of the nine sites WMECO has currently included in the environmental reserve, seven sites are in the remediation or long-term monitoring phase, one site has had some level of site assessments completed, and the remaining site is in the preliminary stages of site assessment.

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

At December 31, 2007, in addition to the nine sites, there is one site for which there are unasserted claims; however, any related site assessment or remediation costs are not probable or estimable at this time. WMECO'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.

MGP Sites: Manufactured gas plant *(*MGP) sites comprise the largest portion of WMECO's environmental liability. MGPs are sites that manufactured gas from coal which produced certain byproducts that may pose a risk to human health and the environment. At both December 31, 2007 and 2006, $0.2 million represents amounts for the site assessment and remediation of MGPs. WMECO currently has three MGP sites included in its environmental liability.

For one MGP site that is included in the company's liability for environmental costs, the information known and nature of the remediation options at that site allow the company to estimate the range of losses for environmental costs. At both December 31, 2007 and 2006, $0.1 million had been accrued as a liability for this site, which represents management's best estimate of the liability for environmental costs. This amount differs from an estimated range of loss from zero to $8.9 million. For the eight 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 nine sites, one is a superfund site under CERCLA for which WMECO has been notified that it is a potentially responsible party (PRP) but for which the site assessment and remediation are not being managed by WMECO. At December 31, 2007, a liability of approximately $30 thousand accrued on this site represents WMECO's estimate of its potential remediation costs with respect to this one superfund sit e.

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: 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.

C. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982 (the Act), 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 its ownership in the Millstone nuclear power station.

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), WMECO has recorded an accrual for the full liability, and payment must be made by WMECO to the DOE prior to the first delivery of spent fuel to the DOE. After the sale of Millstone, WMECO remained responsible for its share of the disposal costs associated with the Prior Period Spent Nuclear Fuel. Until such payment to the DOE is made, the outstanding liability will continue to accrue interest at the 3-month treasury bill yield rate. At December 31, 2007 and 2006, fees due to the DOE for the disposal of Prior Period Spent Nuclear Fuel, net of $0.4 million in interest income earned on the WMECO prior spent nuclear fuel trust for the year ended December 31, 2007, are included in long-term debt and were $55.6 million and $53.4 million, respectively, including accumulated interest costs of $40.4 million and $37.8 million, respectively.

During 2004, WMECO established a trust, which holds marketable securities to fund amounts due to the DOE for the disposal of WMECO's Prior Period Spent Nuclear Fuel. For further information on this trust, see Note 6, "Marketable Securities," to the consolidated financial statements.

D. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of WMECO's significant long-term contractual arrangements are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Totals
VYNPC	$ 4.4	$ 4.7	$ 4.6	$ 4.7	$ 1.1	$ -	$ 19.5
Electricity procurement contracts	2.3	2.3	2.3	-	-	-	6.9
Transmission segment project commitments	11.2	0.1	0.1	0.1	- -	- -	11.5
Hydro-Quebec	2.5	2.5	2.5	2.5	2.5	19.9	32.4
Yankee Companies billings	6.2	5.3	5.6	5.1	5.1	14.7	42.0
Totals	$ 26.6	$ 14.9	$ 15.1	$ 12.4	$ 8.7	$ 34.6	$ 112.3

VYNPC: WMECO has a commitment to buy approximately 2.5 percent of the Vermont Yankee Nuclear Power Corporation (VYNPC) plant's output through March of 2012 at a range of fixed prices. The total cost of purchases under contracts with VYNPC amounted to $4 million in 2007, $5 million in 2006 and $4 million in 2005.

Electricity Procurement Contracts: WMECO has entered into various IPP contracts that extend through 2010 for the purchase of electricity. The total cost of purchases under these contracts amounted to $2.6 million in 2007, $2.1 million in 2006 and $2 million in 2005. These amounts do not include contractual commitments related to WMECO's basic service.

Transmission Segment Project Commitments: These amounts primarily represent commitments for various services and materials associated with WMECO's 115 KV Springfield Underground Cables project and other transmission projects.

Hydro-Quebec: Along with other New England utilities, WMECO has entered into an agreement to support transmission and terminal facilities which were built to import electricity from the Hydro-Quebec system in Canada. WMECO is obligated to pay, over a 30-year period ending in 2020, its proportionate share of the annual O&M expenses and capital costs of those facilities. The total cost of this agreement amounted to $2.2 million in 2007, $2.4 million in 2006 and $2.5 million in 2005.

Yankee Companies Billings: WMECO 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 WMECO. WMECO in turn recovers these costs from its customers through DPU-approved retail rates. The table of estimated future annual costs includes the estimated decommissioning and closure costs for MYAPC, CYAPC and YAEC.

See Note 4E, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements for information regarding the collection of the Yankee Companies' decommissioning costs.

E. Deferred Contractual Obligations

WMECO has significant decommissioning and plant closure cost obligations to the Yankee Companies, which have completed the physical decommissioning of all three of their facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including WMECO. WMECO in turn recovers these costs through DPU-approved retail rates. WMECO's ownership interest in the Yankee Companies at December 31, 2007 is 9.5 percent of CYAPC, 7 percent of YAEC and 3 percent of MYAPC.

WMECO's percentage share of the obligation to support the Yankee Companies under FERC-approved rate tariffs is the same as the ownership percentages above.

CYAPC: Under the terms of the settlement agreement between CYAPC, the Connecticut Department of Public Utility Control (DPUC), the Connecticut Office of Consumer Counsel, and Maine regulators, the parties agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars). Annual collections began in January of 2007, and were reduced from the $93 million originally requested for years 2007 through 2010 to lower levels ranging from $37 million in 2007 rising to $46 million in 2015. The reduction to annual collections was achieved by extending the collection period by 5 years through 2015 by reflecting the proceeds from a settlement agreement with Bechtel Power Corporation, by reducing collections in 2007, 2008 and 2009 by $5 million per year, and making other adjustments. WMECO believes it will recover its share of this obligation from its customers.

YAEC: On July 31, 2006, the FERC approved a settlement agreement with the DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service previously filed by YAEC. This settlement agreement did not materially affect the level of 2006 charges. Under the settlement agreement, YAEC agreed to reduce its November 2005 decommissioning cost increase from $85 million to $79 million. Other terms of the settlement agreement include extending the collection period for charges through December 2014, reconciling and adjusting future charges based on actual decontamination and decommissioning expenses and the decommissioning trust fund's actual investment earnings. WMECO believes that its $5.5 million share of the increase in decommissioning costs will ultimately be recovered from its customers.

MYAPC: MYAPC is collecting revenues from WMECO and other owners that are adequate to recover the remaining cost of decommissioning its plant, and WMECO expects to recover its share of such costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same periods as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related to disallowed spent nuclear fuel pool operating expenses.

The Court of Federal Claims, following precedent set in another case, did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. In December of 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December of 2006, the DOE appealed the ruling, and the Yankee Companies filed a cross-appeal. The refund to WMECO of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. The appeal is expected to be argued in 2008 with a decision from the Court of Appeals to follow.

WMECO's aggregate share of these damages is $7.9 million. 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, WMECO 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

NU provides credit assurances on behalf of subsidiaries, including WMECO, in the form of guarantees and letters of credit (LOCs) in the normal course of business. At December 31, 2007, the maximum level of exposure in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," under guarantees by NU on behalf of WMECO totaled $2.5 million. A majority of these guarantees do not have established expiration dates, and some guarantees have unlimited exposure to commodity price movements. WMECO has no guarantees of the performance of third parties.

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. Transmission Rate Matters and FERC Regulatory Issues

As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (FERC ROE decision), WMECO recorded an estimated regulatory liability for refunds of $2.7 million as of December 31, 2006. In 2007, WMECO completed the customer refunds that were calculated in accordance with the compliance filing required by the FERC ROE decision and refunded approximately $2.5 million to regional, local and localized transmission customers. The $0.2 million positive pre-tax difference ($0.1 million after-tax) between the estimated regulatory liability recorded and the actual amount refunded was recognized in earnings in 2007.

Pursuant to the October 31, 2006 FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. On August 27, 2007, NU, on behalf of WMECO, and the other New England transmission owners submitted a revised compliance filing, which outlined the regional refund process to comply with the FERC's July 26, 2007 order. In addition, the transmission owners filed a request for rehearing claiming that the FERC improperly set the floor for refunds based on the lower rates that the FERC ap proved in its October 31, 2006 order, rather than the last approved rates, for the period from June 3, 2005 to September 3, 2006. The FERC denied this request on January 17, 2008, and the transmission owners have until March 17, 2008 to appeal, if they so choose.

WMECO's transmission segment refunded approximately $0.2 million of revenues and interest related to the July 26, 2007 order (approximately $0.1 million after-tax), which was recorded in 2007.

H. Other Litigation and Legal Proceedings

WMECO is involved in other legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, some of which involve management's best estimate of probable loss as defined by SFAS No. 5, "Accounting for Contingencies." 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.

5. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Prior Spent Nuclear Fuel Trust: During 2004, WMECO established a trust to fund the amounts due to the DOE for its prior spent nuclear fuel obligation. These investments having a cost basis of $55.6 million and $53.4 million for 2007 and 2006, respectively, were recorded at their fair market value of $55.7 million and $53.4 million at December 31, 2007 and 2006, respectively. For further information regarding these investments, see Note 6, "Marketable Securities," to the consolidated financial statements.

Long-Term Debt and Rate Reduction Bonds: The fair value of WMECO's fixed-rate securities is based upon quoted market prices for those issues or similar issues. Adjustable rate securities are assumed to have a fair value equal to their carrying value. The carrying amounts of WMECO's financial instruments and their estimated fair values are as follows:

	At December 31, 2007	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**
Long-term debt -		
Other long-term debt	$ 304.4	$ 298.1
Rate reduction bonds	86.7	91.7

	At December 31, 2006	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**
Long-term debt -		
Other long-term debt	$ 262.2	$ 260.0
Rate reduction bonds	99.4	104.2

Other long-term debt includes $55.6 million and $53.4 million of fees and interest due for spent nuclear fuel disposal costs at December 31, 2007 and 2006, respectively.

Other Financial Instruments: The carrying value of other financial instruments included in current assets and current liabilities approximates their fair value due to the short-term nature of these instruments.

6. Marketable Securities

The following is a summary of WMECO's prior spent nuclear fuel trust assets, which are recorded at their fair values and are included in current and long-term marketable securities on the accompanying consolidated balance sheets. Not included in the amounts below are SERP securities totaling $0.7 million and $0.6 million at December 31, 2007 and 2006, respectively, which are also included in current and long-term marketable securities on the accompanying consolidated balance sheets.

	At December 31,	
(Millions of Dollars)	**2007**	**2006**
WMECO prior spent nuclear fuel trust	$ 55.7	$ 53.4

At December 31, 2007 and 2006, these marketable securities are comprised of the following:

(Millions of Dollars) **At December 31, 2007**	**Amortized Cost**	**Pre-Tax Gross Unrealized Gains**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**
Fixed income securities	$ 55.6	$ 0.1	$ -	$ 55.7

(Millions of Dollars) **At December 31, 2006**	**Amortized Cost**	**Pre-Tax Gross Unrealized Gains**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**
Fixed income securities	$ 53.4	$ 0.1	$ (0.1)	$ 53.4

For the year ended December 31, 2007, WMECO recorded a $0.6 million offset to the spent nuclear fuel trust obligation in long-term debt related to the unrealized losses on securities in the spent nuclear fuel trust. For the year ended December 31, 2006, unrealized losses of $0.1 million were recorded on these securities, the entire amount of which was in a loss position for greater than twelve months.

For information related to the change in net unrealized holding gains and losses included in accumulated other comprehensive income, see Note 9, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

WMECO utilizes the average cost basis method for the WMECO spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities.

For the years ended December 31, 2007, 2006, and 2005, realized gains and losses recognized on the sale of available-for-sale securities are as follows:

(Millions of Dollars)	Realized Gains	Realized Losses	Net Realized Gains/(Losses)
2007	$ 0.1	$ (0.1)	$ -
2006	-	(0.3)	(0.3)
2005	-	(0.4)	(0.4)

These amounts offset the spent nuclear fuel trust obligation in long-term debt.

Proceeds from the sale of these securities, including proceeds from short-term investments, totaled $196.9 million, $123.1 million and $82.9 million for the years ended December 31, 2007, 2006, and 2005, respectively.

At December 31, 2007, the contractual maturities of the available-for-sale securities are as follows:

(Millions of Dollars)	Amortized Cost	Estimated Fair Value
Less than one year	$ 30.8	$ 30.9
One to five years	22.5	22.5
Six to ten years	-	-
Greater than ten years	2.3	2.3
Total	$ 55.6	$ 55.7

Amounts above exclude an additional $0.4 million and $0.3 million of SERP securities that are classified as less than one year and one to greater than ten years, respectively, and are included on the accompanying consolidated balance sheet at December 31, 2007.

For further information regarding marketable securities, see Note 1N, "Summary of Significant Accounting Policies - Marketable Securities" to the consolidated financial statements.

7. Leases

WMECO has entered into lease agreements for the use of data processing and office equipment, vehicles, and office space. In addition, WMECO incurs costs associated with leases entered into by NUSCO and The Rocky River Realty Company. These costs are included below in operating lease payments charged to expense and amounts capitalized as well as future operating lease payments from 2008 through 2012 and thereafter. 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.

There were no capital leases, or interest related to these payments, charged to operating expense in 2007, 2006 and 2005. Operating lease rental payments charged to expense were $4 million in 2007 and 2006 and $3.6 million in 2005. The capitalized portion of operating lease payments was approximately $1.2 million, $1.1 million and $1.1 million for the years ended 2007, 2006 and 2005, respectively.

Future minimum rental payments excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable operating leases, at December 31, 2007 are as follows:

(Millions of Dollars)	Operating Leases
2008	$ 5.0
2009	4.8
2010	4.5
2011	4.1
2012	3.6
Thereafter	7.9
Future minimum lease payments	$ 29.9

8. Dividend Restrictions

The Federal Power Act limits the payment of dividends by WMECO to its retained earnings balance and certain state statutes may impose additional limitations on WMECO. WMECO also has a revolving credit agreement that imposes a leverage restriction tied to its ratio of consolidated total debt to total capitalization.

9. Accumulated Other Comprehensive Income/(Loss)

The accumulated balance for each other comprehensive income/(loss), net of tax, item is as follows:

(Millions of Dollars)	December 31, 2006	Current Period Change	December 31, 2007
Qualified cash flow hedging instruments	$ 0.9	$ (0.7)	$ 0.2
Accumulated other comprehensive income	$ 0.9	$ (0.7)	$ 0.2

(Millions of Dollars)	December 31, 2005	Current Period Change	December 31, 2006
Qualified cash flow hedging instruments	$ 1.0	$ (0.1)	$ 0.9
Unrealized losses on securities	(0.2)	0.2	-
Minimum SERP liability	(0.1)	0.1	-
Accumulated other comprehensive (loss)/income	$ 0.7	$ 0.2	$ 0.9

The changes in the components of other comprehensive loss are reported net of the following income tax effects:

(Millions of Dollars)	2007	2006	2005
Qualified cash flow hedging instruments	$ (0.5)	$ (0.1)	$ (0.6)
Unrealized losses on securities	-	0.2	0.2
Accumulated other comprehensive income/(loss)	$ (0.5)	$ 0.1	$ (0.4)

Fair value adjustments included in accumulated other comprehensive income/(loss) for WMECO's qualified cash flow hedging instruments are as follows:

	At December 31,	
(Millions of Dollars, Net of Tax)	2007	2006
Balance at beginning of year	$ 0.9	$ 1.0
Hedged transactions recognized into earnings	(0.1)	-
Cash flow transactions entered into for period	(0.6)	(0.1)
Net change associated with hedging transactions	(0.7)	(0.1)
Total fair value adjustments included in accumulated other comprehensive income	$ 0.2	$ 0.9

In July of 2007, WMECO entered into a forward interest rate swap agreement to hedge the interest rate associated with its $40 million, 30-year fixed rate long-term debt issuance. Under the agreement, WMECO had a LIBOR swap rate of 5.882 percent based on the notional amount of $40 million in long-term debt that was issued in July of 2007. On August 15, 2007, the hedge was settled and a net of tax charge of $0.6 million ($1 million pre-tax), was recorded in accumulated other comprehensive income to be amortized into earnings over the term of the long-term debt.

It is estimated that a benefit of $0.1 million will be reclassified from accumulated other comprehensive income as an increase to earnings over the next 12 months as a result of amortization of the interest rate swap agreements which have been settled.

10. Long-Term Debt

Details of long-term debt outstanding are as follows:

	At December 31,	
	2007	2006
	(Millions of Dollars)	
Pollution Control Notes:		
Tax Exempt 1993 Series A, 5.85% due 2028	$ 53.8	$ 53.8
Other:		
Taxable Senior Series A, 5.00% due 2013	55.0	55.0
Taxable Senior Series B, 5.90% due 2034	50.0	50.0
Taxable Senior Series C, 5.24% due 2015	50.0	50.0
Taxable Senior Series D, 6.70% due 2037	40.0	-
Total Pollution Control Notes and Other	248.8	208.8
Fees and interest due for spent nuclear fuel disposal costs	55.6	53.4
Total pollution control notes and fees and interest for spent nuclear fuel disposal costs	304.4	262.2
Less amounts due within one year	-	-
Unamortized premium and discount, net	(0.5)	(0.4)
Long-term debt	$ 303.9	$ 261.8

There are no cash sinking fund requirements or debt maturities for the years 2008 through 2012.

On August 17, 2007, WMECO issued $40 million of 30-year Series D senior unsecured notes with a coupon rate of 6.7 percent and a maturity date of August 15, 2037. The proceeds were used to refinance the company's short term borrowings, which were previously incurred to fund transmission and distribution segment capital expenditures.

During 2004, WMECO established a trust with the issuance proceeds from the Taxable Senior Series B 5.9 percent note due 2034. This trust holds marketable securities to fund amounts due upon demand to the DOE for the disposal of WMECO's prior spent nuclear fuel.

For information regarding fees and interest due for spent nuclear fuel disposal costs, see Note 4C, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

11. Segment Information

Segment information related to the distribution and transmission segments for WMECO for the years ended December 31, 2007, 2006 and 2005 is as follows:

	For the Year Ended December 31, 2007		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues (1)	$ 441.6	$ 23.1	$ 464.7
Depreciation and amortization	(41.7)	(2.5)	(44.2)
Other operating expenses	(355.6)	(10.7)	(366.3)
Operating income	44.3	9.9	54.2
Interest expense, net of AFUDC	(17.7)	(2.1)	(19.8)
Interest income	1.5	0.7	2.2
Other income, net	1.6	-	1.6
Income tax benefit	(11.2)	(3.4)	(14.6)
Net income	$ 18.5	$ 5.1	$ 23.6
Total assets (2)	$ 991.1	$ -	$ 991.1
Cash flows for total investments in plant (3)	$ 29.9	$ 17.4	$ 47.3

	For the Year Ended December 31, 2006		
	Distribution	Transmission	Totals
Operating revenues (1)	$ 410.9	$ 20.6	$ 431.5
Depreciation and amortization	0.7	(2.4)	(1.7)
Other operating expenses	(380.0)	(9.8)	(389.8)
Operating income	31.6	8.4	40.0
Interest expense, net of AFUDC	(17.1)	(1.8)	(18.9)
Interest income	0.7	-	0.7
Other income, net	1.4	0.2	1.6
Income tax benefit	(5.6)	(2.2)	(7.8)
Net income	$ 11.0	$ 4.6	$ 15.6
Total assets (2)	$ 988.7	$ -	$ 988.7
Cash flows for total investments in plant (3)	$ 29.7	$ 13.1	$ 42.8

	For the Year Ended December 31, 2005		
	Distribution	Transmission	Totals
Operating revenues (1)	$ 391.1	$ 18.3	$ 409.4
Depreciation and amortization	(22.0)	(2.0)	(24.0)
Other operating expenses	(335.8)	(9.3)	(345.1)
Operating income	33.3	7.0	40.3
Interest expense, net of AFUDC	(17.0)	(1.1)	(18.1)
Interest income	0.4	-	0.4
Other income, net	1.6	0.2	1.8
Income tax benefit	(7.2)	(2.1)	(9.3)
Net income	$ 11.1	$ 4.0	$ 15.1
Cash flows for total investments in plant (3)	$ 32.4	$ 12.3	$ 44.7

(1) WMECO revenues are primarily derived from residential, commercial and industrial customers and are not dependent on any single customer.

(2) Information for segmenting total assets between distribution and transmission is not available at December 31, 2007 and 2006. The distribution and transmission assets are disclosed in the distribution columns above.

(3) Cash flows for total investment in plant included in the segment information above are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income.

Consolidated Quarterly Financial Data (Unaudited)

(Thousands of Dollars)	Quarter Ended March 31,	June 30,	September 30,	December 31,
2007				
Operating Revenues	$ 129,558	$ 112,363	$ 113,500	$ 109,324
Operating Income	15,435	12,314	13,562	12,840
Net Income	6,917	4,590	5,340	6,757
2006				
Operating Revenues	$ 129,040	$ 99,037	$ 104,959	$ 98,473
Operating Income	12,176	10,369	10,611	6,817
Net Income	5,177	2,629	3,672	4,166

Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2007	2006	2005	2004	2003
Operating Revenues	$ 464,745	$ 431,509	$ 409,393	$ 379,229	$ 391,178
Net Income	23,604	15,644	15,085	12,373	16,212
Cash Dividends on Common Stock	12,779	7,946	7,685	6,485	22,011
Property, Plant and Equipment (a)	559,357	526,094	499,317	468,884	447,771
Total Assets	991,088	988,693	945,996	922,472	872,077
Rate Reduction Bonds	86,731	99,428	111,331	122,489	132,960
Long-Term Debt (b)	303,872	261,777	259,487	207,684	157,202
Obligations Under Capital Leases (b)	-	-	-	-	57

(a) Amount includes construction work in progress.

(b) Includes portions due within one year, but includes rate reduction bonds.

Selected Consolidated Sales Statistics (Unaudited)

	2007	2006	2005	2004	2003
Revenues: *(Thousands)*					
Residential	$ 246,526	$ 232,197	$ 190,023	$ 167,275	$ 165,871
Commercial	140,531	132,336	133,356	128,425	133,122
Industrial	48,036	43,131	59,937	62,347	63,990
Other Utilities	20,131	17,421	19,064	8,646	14,347
Streetlighting and Railroads	4,492	5,025	5,030	4,782	4,817
Miscellaneous	5,029	1,399	1,983	7,754	9,031
Total	$ 464,745	$ 431,509	$ 409,393	$ 379,229	$ 391,178
Sales: *(KWH - Millions)*					
Residential	1,539	1,511	1,596	1,546	1,521
Commercial	1,589	1,574	1,616	1,583	1,567
Industrial	842	862	910	935	909
Other Utilities	178	189	176	169	255
Streetlighting and Railroads	25	25	25	25	26
Total	4,173	4,161	4,323	4,258	4,278
Customers: *(Average)*					
Residential	187,854	187,252	186,882	185,083	185,202
Commercial	17,096	17,310	19,174	18,917	18,838
Industrial	777	798	894	892	897
Other	703	705	714	695	693
Total	206,430	206,065	207,664	205,587	205,630

2007 Annual Report
Public Service Company of New Hampshire

Company Report

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the related notes included in this Annual Report. References in this exhibit to "PSNH" or "the company" are to Public Service Company of New Hampshire, and the terms "we," "us" and "our" refer to PSNH.

Overview
We are a wholly owned subsidiary of Northeast Utilities (NU). NU's other regulated electric subsidiaries include The Connecticut Light and Power Company and Western Massachusetts Electric Company.

We earned $54.4 million in 2007, compared with $35.3 million in 2006 and $41.7 million in 2005. Included in earnings were transmission segment earnings of $10.7 million, $8.3 million and $7.8 million in 2007, 2006 and 2005, respectively, and distribution and generation segment earnings of $43.7 million, $27 million and $33.9 million in 2007, 2006 and 2005, respectively.

Our distribution and generation segment earnings in 2007 were $16.7 million higher than in 2006 primarily due to a $24.5 million annualized temporary rate increase that took effect on July 1, 2006; a $37.7 million annualized energy delivery rate increase that took effect on July 1, 2007; recovery of approximately $4.5 million of pre-tax retail transmission costs that were expensed in 2006; the implementation of a retail transmission cost tracking mechanism; and lower unitary state income taxes. The increases were partially offset by higher operations and maintenance expense, higher depreciation, and higher interest expense. Our distribution and generation segment regulatory return on equity (Regulatory ROE) was 9.5 percent in 2007 and 6.4 percent in 2006. We expect our distribution and generation segment Regulatory ROE to be towards the low end of a 9 percent to 10 percent range at approximately 9 percent in 2008. &nb sp;

The increase in transmission segment earnings in 2007 was due to a higher level of investment in our transmission infrastructure.

For the distribution segment, a summary of changes in our retail electric kilowatt-hour (KWH) sales for 2007 as compared to 2006 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/(Decrease)
Residential	2.9 %	1.5 %
Commercial	1.8 %	1.6 %
Industrial	(3.4)%	(3.2)%
Other	4.9 %	4.9 %
Total	1.2 %	0.6 %

Our electric sales per customer, adjusted for weather impacts, have been negatively affected by retail rate increases driven by the energy component of customer bills in early 2006. Although the longer-term trend in customer usage in our service territory when energy prices were stable had reflected a generally increasing use per customer, customers have responded to higher energy prices in recent years by using less electricity. PSNH's overall electric rates decreased in 2007 and use per customer has returned to 2005 levels. We cannot determine at this time whether these trends will continue or the effect they may have on our distribution segment earnings.

Liquidity
Net cash flows from operations decreased by $26.5 million from $173.8 million in 2006 to $147.3 million in 2007. The decrease in operating cash flows was primarily due to a $76 million reduction in stranded cost recovery charge (SCRC) revenues as a result of reductions in the approved SCRC rate. The SCRC rate was initially decreased effective July 1, 2006 as a result of all Part 3 stranded costs being recovered as of June 30, 2006. The average SCRC rate for 2007 was further reduced effective January 1, 2007, which reflects lower expected stranded cost recovery in 2007. This decrease was offset by lower cash tax payments made during 2007 as compared to 2006 and higher working capital requirements.

We, along with other NU subsidiaries, are a party to a five-year unsecured revolving credit facility which expires on November 6, 2010. We can borrow up to $100 million on a short-term basis, or subject to regulatory approvals, on a long-term basis. At December 31, 2007, we had $10 million in short-term borrowings under this facility. The weighted-average interest rate on these short-term borrowings at December 31, 2007 was 7.25 percent. At December 31, 2006, we had no borrowings outstanding under this facility.

On September 24, 2007, we issued $70 million of first mortgage bonds with a coupon rate of 6.15 percent and a maturity date of September 1, 2017. The proceeds were used to refinance our short-term borrowings, which were previously incurred to fund transmission segment and distribution segment capital expenditures. We expect to issue $110 million of long-term debt in 2008.

Our first mortgage bonds are rated Baa1, BBB+, and BBB+ with a stable outlook, by Moody's Investors Service, Standard & Poor's (S&P) and Fitch Ratings, respectively. The only credit ratings change in 2007 occurred when, as part of a comprehensive reassessment of utility secured debt ratings, S&P raised our first mortgage bond ratings by one notch to BBB+. To ensure the consistency of these ratings, which aid in the achievement of competitive market rates for our debt issuances, we seek to maintain certain credit metrics satisfactory to the rating agencies, which include a target capitalization structure of approximately 55 percent debt and 45 percent equity. The three agencies each may include in the debt component of capitalization additional factors, such as the net present value of remaining operating leases and postretirement benefit obligations. Before the application of such adjustmen ts, our ratio of consolidated total debt to total capitalization was approximately 52.7 percent as of December 31, 2007. We seek to maintain our target structure over the long term through a proper balance of capital infusions from NU parent and new debt issuances or borrowings.

In 2007 and 2006, NU contributed equity to us of $44.2 million and $21.7 million, respectively. In general, we pay approximately 60 percent of our cash earnings to NU in the form of common dividends. In 2007 and 2006, we paid common dividends to NU of $30.7 million and $41.7 million, respectively.

Capital expenditures described herein are cash capital expenditures and exclude amounts incurred but not paid, cost of removal, allowance for funds used during construction (AFUDC) related to equity funds, and the capitalized portion of pension expense or income. Our capital expenditures totaled $167.7 million in 2007, compared with $126.7 million in 2006 and $158.8 million in 2005. The increase in expenditures in 2007 from 2006 and 2005 was due to planned enhancements in our transmission system. We expect to incur transmission capital expenditures of $108 million in 2008, which will be financed through the debt issuance noted above, among other sources.

Regulatory Developments

Delivery Service Rate Case: On May 25, 2007, the New Hampshire Public Utilities Commission (NHPUC) approved a distribution and transmission rate case settlement agreement between us, the NHPUC staff and the New Hampshire Office of Consumer Advocate (OCA). The settlement agreement included, among other items, a transmission cost tracking mechanism, effective on July 1, 2006, to be reset annually, and an allowed distribution ROE of 9.67 percent. The settlement agreement allowed for a $37.7 million estimated annualized rate increase ($26.5 million for distribution and $11.2 million for transmission in base rates subject to tracking) beginning on July 1, 2007, along with the previous $24.5 million annualized temporary distribution rate increase that was effective on July 1, 2006. The $37.7 million includes a one-year revenue increase of approximately $9 million related to additional revenues to recoup the dif ference between the temporary and permanent rates for the period of July 1, 2006 through June 30, 2007. An additional delivery revenue increase of $3 million took effect on January 1, 2008 with a final estimated rate decrease of approximately $9 million scheduled for July 1, 2008. The settlement agreement enabled us to fund a $10 million annual reliability enhancement program and more adequately fund our major storm cost reserve.

The pre-tax earnings impact of the approximately $9 million of additional revenues related to the July 1, 2006 through June 30, 2007 time period was or will be recognized as follows: approximately $4.5 million attributable to 2006 retail transmission expense was recognized in the second quarter of 2007; $3 million attributable to distribution costs from July 1, 2006 through June 30, 2007 will be recognized over the 12-month period beginning on July 1, 2007; and the remaining $1.5 million of revenue will be captured as part of the 2007 retail transmission tracker and will be offset by an equal amount of retail transmission expenses.

SCRC/ES Reconciliation and Rates: On May 1, 2007, we filed our 2006 SCRC/energy service (ES) rate reconciliation with the NHPUC. On November 5, 2007, we, the NHPUC Staff, and the OCA filed a proposed settlement with the NHPUC. On December 7, 2007, the settlement, which did not have a material impact on our 2007 earnings, was approved by the NHPUC.

On September 7, 2007, we filed a petition with the NHPUC requesting a change in our SCRC rate for the period January 1, 2008 through December 31, 2008. The NHPUC issued an order on December 17, 2007, approving our SCRC rate of $0.0072 per KWH for 2008.

On September 7, 2007, we filed a petition with the NHPUC requesting a change in our default ES rate for the period January 1, 2008 through December 31, 2008. The NHPUC issued an order on December 28, 2007, approving an ES rate of $0.0882 per KWH for 2008. As part of its order approving the ES rate, the NHPUC approved an increase in the allowed return on generation assets from 9.62 percent to 9.81 percent effective on January 1, 2008.

TCAM Rates: On June 1, 2007, we filed a petition with the NHPUC seeking to establish a transmission cost adjustment mechanism (TCAM) rate consistent with the rate case settlement agreement that was approved by the NHPUC on May 25, 2007. The TCAM rate filing was amended on June 6, 2007 to reflect updates to wholesale transmission rates that were made available to us after the initial June 1, 2007 filing. The NHPUC issued an order on June 29, 2007 approving a TCAM rate of $0.00752 per KWH for the period July 1, 2007 through June 30, 2008.

RESULTS OF OPERATIONS

The components of significant income statement variances for the past two years are provided in the table below.

Income Statement Variances	2007 over/(under) 2006		2006 over/(under) 2005	
(Millions of Dollars)	Amount	Percent	Amount	Percent
Operating Revenues	$ (58)	(5) %	$ 12	1 %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(58)	(10)	72	14
Other operation	30	17	-	-
Maintenance	3	4	7	11
Depreciation	4	7	3	7
Amortization of regulatory assets, net	(46)	(86)	(92)	(63)
Amortization of rate reduction bonds	3	6	3	6
Taxes other than income taxes	2	5	1	3
Total operating expenses	(62)	(6)	(6)	(1)
Operating Income	4	3	18	19
Interest expense, net	-	-	(1)	(1)
Other income, net	(1)	(9)	2	39
Income before income tax expense	3	4	21	38 %
Income tax expense	(16)	(42)	27	(a)
Net income	$ 19	54 %	$ (6)	(15) %

(a) Percent greater than 100.

Comparison of the Year 2007 to the Year 2006

Operating Revenues
Operating revenues decreased by $58 million due to lower distribution revenues ($64 million), partially offset by higher transmission segment revenues ($6 million).

The distribution segment revenue decrease of $64 million was due to the decrease of the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($87 million), partially offset by increase of the distribution component of PSNH's retail revenues which impacts earnings ($24 million). The distribution revenue tracking components decrease of $87 million was primarily due to a decrease in the SCRC revenue ($76 million) mainly as a result of rate decreases effective July 1, 2006 and July 1, 2007, lower wholesale revenues ($27 million) and the pass through of lower energy supply costs ($15 million), partially offset by higher retail transmission revenues ($17 million), higher REC revenue from the Northern Wood Power Plant ($8 million) and higher System Benefits Charge revenue ($4 million). The tracking mechanisms allow for rates to be ch anged periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of PSNH’s retail revenues which impacts earnings increased $24 million, as a result of the rate increases effective July 1, 2006 and July 1, 2007, and higher sales. Retail sales increased 1.2 percent in 2007 compared to 2006.

Transmission segment revenues increased $6 million primarily due to a higher transmission investment base and higher operating expenses which are recovered under Federal Energy Regulatory Commission (FERC)-approved transmission tariffs.

Fuel
Fuel, purchased and net interchange power costs decreased $58 million primarily due to a decrease in the purchase of higher priced Independent Power Producers’ power as contracts expired.

Other Operation
Other operation expenses increased $30 million primarily due to higher retail transmission expenses ($13 million), higher administrative and general expenses ($8 million), and higher customer assistance costs ($4 million), primarily due to the Electric Assistance Program (EAP).

Maintenance
Maintenance expenses increased $3 million primarily due to higher overhead line maintenance expenses.

Depreciation
Depreciation expense increased $4 million primarily due to higher utility plant balances.

Amortization of Regulatory Assets, Net
Amortization of regulatory assets decreased $46 million primarily due to lower ES over recoveries ($27 million), lower stranded cost amortization levels, primarily as a result of PSNH's full recovery of non-securitized stranded costs in June 2006 ($13 million) and the deferral of retail transmission costs through the TCAM, which was implemented in 2007 ($5 million).

Amortization of Rate Reduction Bonds
Amortization of rate reduction bonds increased $3 million. The higher portion of principal within the rate reduction bonds' payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $2 million primarily due to higher property taxes ($1 million) and higher payroll-related taxes ($1 million).

Other Income, Net
Other income, net decreased $1 million primarily due to lower AFUDC, as a result of decreased eligible construction work in progress (CWIP) for generation, higher short-term debt and a lower portion of CWIP being subject to the equity rate.

Income Tax Expense
Income tax expense decreased $16 million due to a decrease in the effective tax rate to 29.5 percent. The decrease in the effective tax rate was due to an increase in tax credits, decrease in state tax expense and lower flow through regulatory amortizations. The increase in tax credits were the result of a full year of production tax credits at the Northern Wood Power Plant. In 2006, flow through regulatory amortizations were higher as a result of the regulatory recovery in revenue of income tax expense associated with non-deductible acquisition costs.

Comparison of the Year 2006 to the Year 2005

Operating Revenues
Operating revenues increased $12 million primarily due to higher distribution segment revenue ($8 million) and higher transmission segment revenue ($4 million).

The distribution segment revenue increase of $8 million was primarily due to the distribution and transmission components of PSNH's retail rates which impact earnings ($15 million), as a result of the rate increases effective July 1, 2006, partially offset by lower retail sales. Retail sales decreased 1.3 percent in 2006 compared to the same period of 2005.

The components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs decreased $7 million primarily due to a decrease in the SCRC ($85 million) mainly as a result of a rate decrease effective July 1, 2006, partially offset by an increase in the default ES rate component of retail revenues ($80 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.

Transmission segment revenues increased $4 million primarily due to a higher rate base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power increased $72 million primarily due to the higher cost of energy as a result of higher fuel prices, which are included in regulatory commission approved tracking mechanisms.

Maintenance
Maintenance expenses increased $7 million primarily due to higher generation costs ($4 million), mainly due to higher boiler maintenance costs as a result of the planned overhaul of a generating plant in 2006, and higher overhead line maintenance expenses ($2 million).

Depreciation
Depreciation expense increased $3 million primarily due to higher plant balances resulting from the ongoing construction program.

Amortization of Regulatory Assets, Net
Amortization of regulatory assets, net decreased $92 million primarily due to PSNH completing the recovery of certain identified non-securitized stranded costs in June of 2006, partially offset by higher amortization expense, which was primarily the result of an ES deferral from February and March of 2006, where ES revenues exceeded ES costs ($23 million).

Amortization of Rate Reduction Bonds
Amortization of rate reduction bonds increased $3 million. The higher portion of principal within the rate reduction bonds' payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $1 million primarily due to higher property taxes.

Interest Expense, Net
Interest expense decreased $1 million primarily due to lower rate reduction bond interest resulting from lower principal balances outstanding ($3 million), partially offset by higher long-term debt levels as a result of the issuance of $50 million of thirty-year first mortgage bonds in October of 2005 ($2 million).

Other Income, Net
Other income, net increased $2 million primarily due to a higher AFUDC ($3 million), as a result of increased eligible construction work in progress (CWIP) for generation, lower short-term debt, and a higher portion of CWIP being subject to the equity rate, partially offset by lower C&LM incentive income ($1 million), as a result of the 2004 incentive being recorded in 2005.

Income Tax Expense
Income tax expense increased $27 million due to higher pre-tax earnings and an increase in the effective tax rate from 22.7 percent to 52.6 percent. The increase in the effective tax rate primarily resulted from the loss of a state unitary tax benefit due to the sale of competitive generation assets and the regulatory recovery of federal and state tax expense associated with nondeductible acquisition costs. The regulatory recovery of federal and state tax expense associated with nondeductible acquisition costs caused a decrease in amortization and offsetting increase in income tax expense. This recovery had no impact on net income but increased the effective tax rate.

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 Public Service Company of New Hampshire and subsidiaries (PSNH or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, PSNH conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that our internal controls over financial reporting were effective as of December 31, 2007.

February 28, 2008

Report of Independent Registered Public Accounting Firm

To the Board of Directors of
Public Service Company of New Hampshire:

We have audited the accompanying consolidated balance sheets of Public Service Company of New Hampshire and subsidiaries (a New Hampshire corporation and a wholly owned subsidiary of Northeast Utilities) (the "Company") as of December 31, 2007 and 2006, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Public Service Company of New Hampshire and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1.G., the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, as of January 1, 2007.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
February 28, 2008

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

At December 31,	2007	2006
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 450	$ 31
Receivables, less provision for uncollectible accounts of $2,675 in 2007 and $2,626 in 2006	97,749	86,784
Accounts receivable from affiliated companies	817	590
Unbilled revenues	45,607	44,433
Taxes receivable	255	6,671
Fuel, materials and supplies	72,215	84,856
Derivative assets - current	6,146	-
Prepayments and other	14,327	12,652
	237,566	236,017
Property, Plant and Equipment:		
Electric utility	2,010,220	1,898,940
Less: Accumulated depreciation	737,917	723,764
	1,272,303	1,175,176
Construction work in progress	116,102	67,202
	1,388,405	1,242,378
Deferred Debits and Other Assets:		
Regulatory assets	401,374	524,536
Derivative assets - long-term	12,075	-
Other	67,549	68,345
	480,998	592,881
Total Assets	$ 2,106,969	$ 2,071,276

The accompanying notes are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

At December 31,	2007	2006
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 10,000	$ -
Notes payable to affiliated companies	11,300	36,500
Accounts payable	91,356	69,948
Accounts payable to affiliated companies	15,717	22,327
Accrued interest	9,175	8,641
Derivative liabilities - current	2,453	39,180
Other	22,664	2,362
	162,665	178,958
Rate Reduction Bonds	282,018	333,831
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	192,094	200,136
Accumulated deferred investment tax credits	582	877
Deferred contractual obligations	28,215	35,623
Regulatory liabilities	127,569	115,731
Accrued pension	138,346	150,634
Accrued postretirement benefits	29,057	36,521
Other	31,559	44,304
	547,422	583,826
Capitalization:		
Long-Term Debt	576,997	507,099
Common Stockholder's Equity:		
Common stock, $1 par value - authorized 100,000,000 shares; 301 shares outstanding in 2007 and 2006	-	-
Capital surplus, paid in	275,569	231,171
Retained earnings	261,528	236,215
Accumulated other comprehensive income	770	176
Common Stockholder's Equity	537,867	467,562
Total Capitalization	1,114,864	974,661
Commitments and Contingencies (Note 5)		
Total Liabilities and Capitalization	$ 2,106,969	$ 2,071,276

The accompanying notes are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2007	2006	2005
		(Thousands of Dollars)	
Operating Revenues	$ 1,083,072	$ 1,140,900	$ 1,128,427
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	530,680	588,132	515,801
Other	208,691	178,577	179,003
Maintenance	74,070	71,400	64,200
Depreciation	53,315	49,740	46,567
Amortization of regulatory assets, net	7,470	53,156	144,746
Amortization of rate reduction bonds	52,344	49,370	46,648
Taxes other than income taxes	39,671	37,640	36,498
Total operating expenses	966,241	1,028,015	1,033,463
Operating Income	116,831	112,885	94,964
Interest Expense:			
Interest on long-term debt	26,029	24,100	20,481
Interest on rate reduction bonds	18,013	20,828	24,074
Other interest	2,243	829	1,733
Interest expense, net	46,285	45,757	46,288
Other Income, Net	6,682	7,378	5,297
Income Before Income Tax Expense	77,228	74,506	53,973
Income Tax Expense	22,794	39,183	12,234
Net Income	$ 54,434	$ 35,323	$ 41,739
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME			
Net Income	$ 54,434	$ 35,323	$ 41,739
Other comprehensive income, net of tax:			
Qualified cash flow hedging instruments	605	-	-
Unrealized (losses)/gains on securities	(11)	32	(39)
Minimum SERP liability	-	61	232
Other comprehensive income, net of tax	594	93	193
Comprehensive Income	$ 55,028	$ 35,416	$ 41,932

The accompanying notes are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock		Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive (Loss)/Income	Total
	Shares	Amount				
			(Thousands of Dollars, except share information)			
Balance at January 1, 2005	301	$ -	$ 156,532	$ 243,277	$ (110)	$ 399,699
Net income for 2005				41,739		41,739
Dividends on common stock				(42,383)		(42,383)
Allocation of benefits - ESOP			(208)			(208)
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			45			45
Capital contribution from NU parent			53,419			53,419
Other comprehensive income					193	193
Balance at December 31, 2005	301	-	209,788	242,633	83	452,504
Net income for 2006				35,323		35,323
Dividends on common stock				(41,741)		(41,741)
Allocation of benefits - ESOP			(68)			(68)
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			(242)			(242)
Capital contribution from NU parent			21,693			21,693
Other comprehensive income					93	93
Balance at December 31, 2006	301	-	231,171	236,215	176	467,562
Adoption of FIN 48 - accounting for uncertainty of income taxes				1,599		1,599
Net income for 2007				54,434		54,434
Dividends on common stock				(30,720)		(30,720)
Allocation of benefits - ESOP			204			204
Capital contribution from NU parent			44,194			44,194
Other comprehensive income					594	594
Balance at December 31, 2007	301	$ -	$ 275,569	$ 261,528	$ 770	$ 537,867

The accompanying notes are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2007	2006	2005
		(Thousands of Dollars)	
Operating activities:			
Net income	$ 54,434	$ 35,323	$ 41,739
Adjustments to reconcile to net cash flows provided by operating activities:			
Bad debt expense	3,433	4,208	3,904
Depreciation	53,315	49,740	46,567
Deferred income taxes	(4,726)	(21,929)	(68,347)
Amortization of regulatory assets, net	7,470	53,156	144,746
Amortization of rate reduction bonds	52,344	49,370	46,648
Pension expense, net of capitalized portion	14,722	15,963	14,338
Regulatory (underrecoveries)/overrecoveries	(6,167)	(6,850)	478
Deferred contractual obligations	(6,365)	(12,589)	(12,465)
Other non-cash adjustments	(4,192)	(5,379)	(8,468)
Other sources of cash	-	-	342
Other uses of cash	(15,126)	(11,882)	(19,962)
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(15,799)	27,637	(18,799)
Taxes accrued/(receivable)	4,144	(11,857)	9,684
Fuel, materials and supplies	15,882	(12,036)	(16,300)
Other current assets	(1,949)	5,106	1,170
Accounts payable	(8,178)	14,073	(9,009)
Other current liabilities	4,051	1,764	(1,013)
Net cash flows provided by operating activities	147,293	173,818	155,253
Investing Activities:			
Investments in property and plant	(167,712)	(126,657)	(158,832)
Proceeds from sales of investment securities	3,454	3,788	3,227
Purchases of investment securities	(3,692)	(4,059)	(3,415)
Net proceeds from sale of property	-	-	1,461
Other investing activities	5,921	2,564	(2,767)
Net cash flows used in investing activities	(162,029)	(124,364)	(160,326)
Financing Activities:			
Issuance of long-term debt	70,000	-	50,000
Retirement of rate reduction bonds	(51,813)	(48,861)	(46,077)
Increase/(decrease) in short-term debt	10,000	-	(10,000)
(Decrease)/increase in NU Money Pool borrowings	(25,200)	20,600	(4,500)
Capital contributions from NU parent	44,194	21,693	53,419
Cash dividends on common stock	(30,720)	(41,741)	(42,383)
Other financing activities	(1,306)	(1,141)	(214)
Net cash flows provided by/(used in) financing activities	15,155	(49,450)	245
Net increase/(decrease) in cash	419	4	(4,828)
Cash - beginning of year	31	27	4,855
Cash - end of year	$ 450	$ 31	$ 27
Supplemental Cash Flow Information:			
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 50,237	$ 49,305	$ 48,165
Income taxes	$ 26,167	$ 75,198	$ 72,140
Non-cash investing activities:			
Capital expenditures incurred but not paid	$ 37,811	$ 15,036	$ 17,093

The accompanying notes are an integral part of these consolidated financial statements.

1. Summary of Significant Accounting Policies

A. About Public Service Company of New Hampshire

Public Service Company of New Hampshire (PSNH or the company) is a wholly-owned subsidiary of Northeast Utilities (NU). PSNH is a reporting company under the Securities Exchange Act of 1934. Until February 8, 2006, NU was registered with the Securities and Exchange Commission as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). On February 8, 2006, the 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 PSNH, 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. PSNH is subject to further regulation for rates, accounting and other matters by the FERC and the New Hampshire Public Utilities Commission (NHPUC), as well a s certain regulatory oversight by the Vermont Department of Public Service and the Maine Public Utilities Commission. PSNH furnishes franchised retail electric service in New Hampshire. PSNH's results include the operations of its distribution/generation and transmission segments.

Several wholly-owned subsidiaries of NU provide support services for NU's companies, including PSNH. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. Two other subsidiaries construct, acquire or lease some of the property and facilities used by PSNH.

At December 31, 2007 and 2006, PSNH had a long-term receivable from NUSCO in the amount of $3.8 million that is included in other deferred debits on the accompanying consolidated balance sheets related to the funding of investments held by NUSCO in connection with certain postretirement benefits for PSNH employees.

Included in the consolidated balance sheet at December 31, 2007 are accounts receivable from affiliated companies and accounts payable to affiliated companies totaling $0.8 million and $15.7 million, respectively, relating to transactions between PSNH and other subsidiaries that are wholly owned by NU. At December 31, 2006, these amounts totaled $0.6 million and $22.3 million, respectively.

In 2007, PSNH made a discretionary contribution of $0.6 million to the NU Foundation, Inc. (Foundation), an independent not-for-profit charitable entity designed to invest in projects that emphasize economic development, workforce training and education, and a clean and healthy environment. The board of directors of the Foundation consists of certain NU officers. Any donations made to the Foundation negatively impact the earnings of PSNH.

B. Presentation

The consolidated financial statements of PSNH include the accounts of its subsidiaries, PSNH Funding LLC, PSNH Funding LLC 2 and Properties, Inc. 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.

C. Accounting Standards Issued But Not Yet Adopted

Fair Value Measurements: On September 15, 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is applicable to fair value measurements of derivative contracts that are subject to mark-to-market accounting and to other assets and liabilities that are reported at fair value or subject to fair value measurements.

Management is currently evaluating the effects of implementing SFAS No. 157, which would only impact the consolidated balance sheet. Updates to the fair values of derivatives to reflect their exit prices and nonperformance risk would be recorded in regulatory assets or liabilities.

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 is effective in the first quarter of 2008, with the effect of application to eligible items as of January 1, 2008 required to be reflected as a cumulative-effect adjustment to the opening balance of retained earnings. If a company elects the fair value option for an eligible item, changes in that item's fair value at subsequent reporting dates must be recognized in earnings. Management is currently evaluating whether or not to elect the fair value option for PSNH's securit ies held in trust as of January 1, 2008. Implementation of SFAS No. 159 for PSNH's securities held in trust is not expected to have a material effect on the consolidated financial statements.

D. Revenues

PSNH's retail revenues are based on rates approved by the NHPUC. In general, rates can only be changed through formal proceedings with the NHPUC.

Unbilled Revenues: Unbilled revenues represent an estimate of electricity 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 or under other circumstances.

PSNH estimates 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.

Transmission Revenues - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of NU's wholesale transmission revenues are collected under the New England Independent System Operator (ISO-NE) FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Local Network Service (LNS) rate schedules to recover transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users including PSNH's transmission business, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, administered by NU, is reset on January 1st and June 1st of each year and recovers the revenue requirement s for local transmission facilities and other transmission costs not recovered under the RNS rate. The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to retail customers. At December 31, 2007, the LNS rates for PSNH's transmission segment were in an underrecovery position of approximately $3 million, which will be recovered from LNS customers in mid-2008. PSNH believes that these rates will provide it with timely recovery of transmission costs, including costs of its major transmission projects.

Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution segments of PSNH and other NU companies, which recover these costs through rates charged to their retail customers. PSNH implemented a transmission cost adjustment mechanism that was effective on a retroactive basis beginning on July 1, 2006 as part of its February 26, 2007 rate case settlement agreement. This tracking mechanism allows PSNH to charge its retail customers for transmission charges on a timely basis.

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.

Certain PSNH contracts for the purchase or sale of energy or energy-related products are derivatives. Derivative contracts that are elected as and meet the requirements of a normal purchase or sale are recognized in revenues or expenses, as applicable, when the quantity of the contract is delivered. Election of the normal purchases and sales exception (and resulting accrual accounting) for derivatives requires the conclusions 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. Certain PSNH contracts that are not elected as or do not meet the normal purchases and sales criteria are recorded at fair value as derivative assets and liabilities with offsetting amounts recorded as regulatory liabilities and assets because the contracts are p art of providing regulated electric service and because management believes that these amounts will be recovered or refunded in rates.

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 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.

For further information regarding PSNH's derivative contracts, and their accounting, see Note 3, "Derivative Instruments," to the consolidated financial statements.

F. Regulatory Accounting

The accounting policies of PSNH 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, distribution and generation segments of PSNH 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 PSNH will recover its investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning an equity return, except for securitized regulatory assets and deferred benefit costs, which are not supported by equity. Amortization and deferrals of regulatory assets are included on a net basis in amortization expense on the accompanying consolidated statements of income.

Regulatory Assets: The components of PSNH's regulatory assets are as follows:

	At December 31,	
(Millions of Dollars)	**2007**	**2006**
Securitized assets	$ 273.2	$ 325.6
Deferred benefit costs	50.4	90.4
Income taxes, net	10.3	5.5
Regulatory assets offsetting derivative liabilities	2.5	39.2
Other	65.0	63.8
Totals	$ 401.4	$ 524.5

Securitized Assets: In April of 2001, PSNH issued rate reduction bonds in the amount of $525 million. PSNH used the majority of the proceeds from that issuance to buydown its affiliated power contracts with North Atlantic Energy Corporation. The unamortized PSNH securitized asset balance was $272.4 million and $314.7 million at December 31, 2007 and 2006, respectively. In January of 2002, PSNH issued an additional $50 million in rate reduction bonds and used the proceeds from that issuance to repay short-term debt that was incurred to buyout a purchased-power contract in December of 2001. The unamortized PSNH securitized asset balance for the January of 2002 issuance was $0.8 million and $10.9 million at December 31, 2007 and 2006, respectively. The January 2002 rate reduction bonds are expected to be paid in full in the first quarter of 2008.

Securitized regulatory assets, which are not earning an equity return, are being recovered over the amortization period of their associated rate reduction bonds. PSNH rate reduction bonds are scheduled to fully amortize by May 1, 2013.

Deferred Benefit Costs: On December 31, 2006, the company implemented SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." SFAS No. 158 applies to NU's Pension Plan, Supplemental Executive Retirement Plan (SERP), and postretirement benefits other than pension (PBOP) Plan, of which each includes eligible employees of PSNH, 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 PSNH is a cost-of-service, rate regulated entity under SFAS No. 71, offsets were recorded as a regulatory asset of $50.4 million at December 31, 2007 and $90.4 million at December 31, 2006, as these amounts have been and continue to be recoverable in cost-of-service, regulated rates. Regulat ory accounting was also applied to the portions of the NUSCO costs that support PSNH, as these amounts are also recoverable. The deferred benefit costs are not in rate base.

Income Taxes, Net: The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income, including those differences relating to uncertain tax positions) is accounted for in accordance with the rate-making treatment of the NHPUC, SFAS No. 109 and FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." Differences in income taxes between SFAS No. 109, FIN 48 and the rate-making treatment of the NHPUC are recorded as regulatory assets which totaled $10.3 million and $5.5 million at December 31, 2007 and 2006, respectively. For further information regarding income taxes, see Note 1G, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial stat ements.

Regulatory Assets Offsetting Derivative Liabilities: The regulatory assets offsetting derivative liabilities relate to the fair value of contracts used to purchase power and other related contracts that will be collected from customers in the future. These amounts totaled $2.5 million and $39.2 million at December 31, 2007 and 2006, respectively. See Note 3, "Derivative Instruments," for further information. This asset is excluded from rate base.

Other Regulatory Assets: Included in other regulatory assets are the regulatory assets associated with the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $13.3 million and $15.8 million at December 31, 2007 and 2006, respectively. Of these amounts, $11.6 million and $13.7 million, respectively, have been approved for future recovery. Management believes that the remaining regulatory assets are probable of recovery.

At December 31, 2007 and 2006, other regulatory assets also included $10.9 million and $11.7 million, respectively, related to losses on reacquired debt, $2.3 million and $4.4 million, respectively, related to environmental costs, $15 million and $16.7 million, respectively, related to the buyout and buydown of other IPP contracts and $23.5 million and $15.2 million, respectively, related to various other items.

Regulatory Liabilities: The components of regulatory liabilities are as follows:

	At December 31,	
(Millions of Dollars)	**2007**	**2006**
Cost of removal	$ 72.8	$ 79.2
Regulatory liabilities offsetting derivative assets	17.2	-
Deferred ES revenue, net	17.6	18.3
Deferred environmental credit revenue	10.1	10.1
Other regulatory liabilities	9.9	8.1
Totals	$ 127.6	$ 115.7

Cost of Removal: PSNH currently recovers amounts in rates for future costs of removal of plant assets. These amounts, which totaled $72.8 million and $79.2 million at December 31, 2007 and 2006, respectively, are classified as regulatory liabilities on the accompanying consolidated balance sheets. This liability is included in rate base.

Regulatory Liabilities Offsetting 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. This amount totaled $17.2 million at December 31, 2007. See Note 3, "Derivative Instruments," for further information. This liability is excluded from rate base.

Deferred ES Revenue, Net: PSNH 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. The ES deferral of $17.6 million and $18.3 million at December 31, 2007 and 2006, respectively, has been recorded as a regulatory liability on the accompanying consolidated balance sheets.

Deferred Environmental Credit Revenue: PSNH recorded a regulatory obligation to credit ratepayers for accelerated recovery of certain Clean Air Act capital improvements allowed in prior years. This amount, which totaled $10.1 million at December 31, 2007 and 2006, has been recorded as a regulatory liability on the accompanying consolidated balance sheets. This amount will be refunded to customers in 2008.

Other Regulatory Liabilities: At December 31, 2007 and 2006, other regulatory liabilities included $3.3 million and $3.3 million, respectively, related to the conservation and load management incentive that will be refunded to customers in 2008 and $6.6 million and $4.8 million, respectively, related to various other items.

G. Income Taxes

The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the NHPUC, SFAS No. 109 and FIN 48. Details of income tax expense are as follows:

	For the Years Ended December 31,		
	2007	**2006**	**2005**
		(Millions of Dollars)	
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	$ 21.9	$ 50.5	$ 81.6
State	5.9	11.0	(1.0)
Total current	27.8	61.5	80.6
Deferred income taxes, net:			
Federal	(1.7)	(17.1)	(60.5)
State	(3.0)	(4.8)	(7.5)
Total deferred	(4.7)	(21.9)	(68.0)
Investment tax credits, net	(0.3)	(0.4)	(0.4)
Income tax expense	$ 22.8	$ 39.2	$ 12.2

A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:

	For the Years Ended December 31,		
	2007	2006	2005
	(Millions of Dollars, except percentages)		
Income before income tax expense	$ 77.2	$ 74.5	$ 54.0
Expected federal income tax expense	27.0	26.1	18.9
Tax effect of differences:			
Amortization of regulatory assets	-	13.2	1.8
Federal tax credits (including ITC amortization)	(3.4)	(0.6)	(0.4)
State income taxes, net of federal impact	1.9	4.0	(5.5)
Medicare subsidy	(0.9)	(1.0)	(1.1)
Other, net	(1.8)	(2.5)	(1.5)
Income tax expense	$ 22.8	$ 39.2	$ 12.2
Effective tax rate	29.5 %	52.6 %	22.6 %

NU and its subsidiaries, including PSNH, file a consolidated federal income tax return and file state income tax returns. 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.

Included in 2006 amortization of regulatory assets above is $13 million associated with PSNH's restructuring settlement agreement, which was implemented in 2001. In accordance with the provisions of the restructuring settlement, pre-tax amortization of PSNH non-deductible acquisition costs were $38 million and $5 million in 2006 and 2005, respectively.

The tax effects of temporary differences that give rise to the current and long-term net accumulated deferred tax obligations are as follows:

	At December 31,	
(Millions of Dollars)	2007	2006
Deferred tax liabilities - current:		
Property tax accruals	$ 3.2	$ 3.6
Other	3.0	0.1
Total deferred tax liabilities - current	6.2	3.7
Deferred tax assets - current:		
Derivative liability	1.0	15.5
Other	0.9	1.0
Total deferred tax assets - current	1.9	16.5
Net deferred tax liabilities/(assets) - current	4.3	(12.8)
Deferred tax liabilities - long-term:		
Accelerated depreciation and other plant-related differences	162.6	151.9
Securitized costs	106.0	126.2
Regulatory deferrals	14.0	58.1
Other	23.2	4.5
Total deferred tax liabilities - long-term	305.8	340.7
Deferred tax assets - long-term:		
Regulatory deferrals	27.5	44.2
Employee benefits	77.2	82.1
Other	9.0	14.3
Total deferred tax assets - long-term	113.7	140.6
Net deferred tax liabilities - long-term	192.1	200.1
Net deferred tax liabilities	$ 196.4	$ 187.3

Effective on January 1, 2007, PSNH 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, PSNH recorded estimates for uncertain tax positions in accordance with SFAS No. 5, "Accounting for Contingencies."

As a result of implementing FIN 48, PSNH recognized a cumulative effect of a change in accounting principle of $1.6 million as an increase to the January 1, 2007 balance of retained earnings.

Interest and Penalties: Effective on January 1, 2007, PSNH's accounting policy for the classification of interest and penalties related to FIN 48 is as follows:

- Interest on uncertain tax positions is recorded and classified as a component of other income, net. PSNH recorded accrued interest income of $1 million, which is included in the cumulative effect of a change in accounting principle, as of January 1, 2007. For the year ended December 31, 2007, PSNH recorded interest income of $1.1 million. At December 31, 2007, $2.1 million of accrued interest income was recognized on the accompanying consolidated balance sheet.

- No penalties have been recorded under FIN 48. If penalties are recorded in the future, then the estimated penalties would be classified as a component of other income/(loss), net.

Unrecognized Tax Benefits: Upon adoption of FIN 48 on January 1, 2007, PSNH had unrecognized tax benefits totaling $0.8 million, of which none would impact the effective tax rate, if recognized. As of December 31, 2007, PSNH's unrecognized tax benefits totaled $10.6 million, of which none would impact the effective tax rate, if recognized.

A reconciliation of the activity in unrecognized tax benefits from January 1, 2007 to December 31, 2007 is as follows:

(Millions of Dollars)	
Balance at beginning of year	$ 0.8
Gross increases - prior year	9.8
Balance at end of year	$ 10.6

Tax Positions: NU is currently working to resolve all open tax years. It is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. Management estimates that potential resolutions could result in a zero to $10 million decrease in unrecognized tax benefits by PSNH. This estimated change is related to the timing of deducting expenses for book versus tax purposes, which is not expected to have a material impact on earnings.

Tax Years: The following table summarizes PSNH's tax years that remain subject to examination by major tax jurisdictions at December 31, 2007:

Description	Tax Years
Federal (NU consolidated)	2002 - 2007
New Hampshire	2003 - 2007

H. Property, Plant and Equipment and Depreciation

The following table summarizes PSNH's investments in utility plant at December 31, 2007 and 2006 and the average depreciable life at December 31, 2007:

	Average Depreciable Life	At December 31, 2007	At December 31, 2006
	(Years)	*(Millions of Dollars)*	
Distribution	44.3	$ 1,128.7	$ 1,077.0
Transmission	49.2	291.0	244.7
Generation	27.3	590.5	577.2
Total property, plant and equipment		2,010.2	1,898.9
Less: Accumulated depreciation		(737.9)	(723.7)
Net property, plant and equipment		1,272.3	1,175.2
Construction work in progress		116.1	67.2
Total property, plant and equipment, net		$ 1,388.4	$ 1,242.4

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 NHPUC. Depreciation rates are applied to plant-in-service from the time it is placed in service. When a plant is retired from service, the original cost of the plant is charged to the accumulated provision for depreciation which includes cost of removal less salvage. Cost of removal is classified as a regulatory liability. The depreciation rates for the several classes of utility plant-in-service are equivalent to a composite rate of 2.8 percent in 2007, 2006 and 2005.

I. Equity Method Investments

At December 31, 2007, PSNH owned common stock in three regional nuclear companies (Yankee Companies). Each of the Yankee Companies owned a single nuclear generating plant which has been decommissioned. PSNH's ownership interests in the Yankee Companies at December 31, 2007, which are accounted for on the equity method, were 5 percent of Connecticut Yankee Atomic Power Company (CYAPC), 7 percent of the Yankee Atomic Electric Company (YAEC), and 5 percent of the Maine Yankee Atomic Power Company (MYAPC). The total carrying value of PSNH's ownership interests in CYAPC, MYAPC and YAEC, which is included in deferred debits and other assets - other on the accompanying consolidated balance sheets and the distribution reportable segment, totaled $0.8 million and $1.5 million at December 31, 2007 and 2006, respectively. Earnings related to these equity investments are included in other income, net on the accomp anying consolidated statements of income. For further information, see Note 1M,

"Summary of Significant Accounting Policies - Other Income, Net," to the consolidated financial statements.

For further information, see Note 5C, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements.

J. Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) is included in the cost of PSNH's utility plant and represents the cost of borrowed and equity funds used to finance construction. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of other interest expense, and the AFUDC related to equity funds is recorded as other income on the accompanying consolidated statements of income.

	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	**2007**	**2006**	**2005**
AFUDC:			
Borrowed funds	$ 3.0	$ 2.8	$ 1.9
Equity funds	2.0	4.4	1.6
Totals	$ 5.0	$ 7.2	$ 3.5
Average AFUDC rate	7.0 %	7.3 %	5.5 %

The average AFUDC rate is based on a FERC-prescribed formula that develops an average rate using the cost of a company's short-term financings as well as a company's capitalization (long-term debt and common equity). The average rate is applied to eligible construction work in progress (CWIP) amounts to calculate AFUDC.

K. Asset Retirement Obligations

PSNH implemented FIN 47 on December 31, 2005. FIN 47 requires an entity to recognize a liability for the fair value of an asset retirement obligation (ARO) on the obligation date if the liability's fair value can be reasonably estimated and is conditional on a future event. FIN 47 provides that settlement dates and future costs should be reasonably estimated when sufficient information becomes available and provides guidance on the definition and timing of sufficient information in determining expected cash flows and fair values. Management has identified various categories of AROs, primarily certain assets containing asbestos and hazardous contamination. A fair value calculation, reflecting expected probabilities for settlement scenarios, has been performed.

Because it is a cost-of-service, rate regulated entity, PSNH applies regulatory accounting in accordance with SFAS No. 71, and the costs associated with PSNH's AROs were included in other regulatory assets at December 31, 2007 and 2006.

The fair value of the AROs was recorded as a liability in deferred credits and other liabilities - other with an offset included in property, plant and equipment on the accompanying consolidated balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively.

The following tables present the ARO asset, the related accumulated depreciation, the regulatory asset, and the ARO liabilities at December 31, 2007 and 2006:

	At December 31, 2007			
(Millions of Dollars)	**ARO Asset**	**Accumulated Depreciation of ARO Asset**	**Regulatory Asset**	**ARO Liabilities**
Asbestos	$ 0.9	$ (0.5)	$ 6.9	$ (7.7)
Hazardous contamination	0.5	(0.2)	5.3	(5.9)
Other AROs	-	-	1.1	(1.3)
Total AROs	$ 1.4	$ (0.7)	$ 13.3	$ (14.9)

	At December 31, 2006			
(Millions of Dollars)	**ARO Asset**	**Accumulated Depreciation of ARO Asset**	**Regulatory Asset**	**ARO Liabilities**
Asbestos	$ 1.3	$ (0.7)	$ 7.9	$ (8.8)
Hazardous contamination	0.8	(0.4)	6.6	(7.0)
Other AROs	0.1	-	1.3	(1.5)
Total AROs	$ 2.2	$ (1.1)	$ 15.8	$ (17.3)

A reconciliation of the beginning and ending carrying amounts of PSNH's AROs is as follows:

(Millions of Dollars)	2007	2006
Balance at beginning of year	$ (17.3)	$ (18.4)
Accretion	(0.3)	(0.3)
Changes in estimates	2.9	1.4
Revisions in estimated cash flows	(0.2)	-
Balance at end of year	$ (14.9)	$ (17.3)

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.

L. Fuel, Materials and Supplies

Fuel, materials and supplies include materials purchased primarily for construction, operation and maintenance (O&M) purposes. Fuel, materials and supplies are valued at the lower of average cost or market.

M. Other Income, Net

The pre-tax components of PSNH's other income/(loss) items are as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2007	2006	2005
Other Income:			
Investment income	$ 2.6	$ 1.7	$ 1.0
Equity in earnings of regional nuclear generating companies	0.3	(0.1)	0.2
AFUDC - equity funds	2.0	4.4	1.6
Conservation and load management incentives	1.7	1.4	2.5
Other	0.1	-	-
Total Other Income, Net	$ 6.7	$ 7.4	$ 5.3

Equity in earnings of regional nuclear generating companies relates to PSNH's investment in the Yankee Companies.

N. Provision for Uncollectible Accounts

PSNH 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.

O. Special Deposits

PSNH had amounts on deposit related to PSNH Funding LLC and PSNH Funding LLC 2, which are special purpose entities used to facilitate the issuance of rate reduction bonds. These amounts totaled $24.4 million and $27.8 million at December 31, 2007 and 2006, respectively. In addition, the company had $0.5 million and $2 million in other cash deposits held with unaffiliated parties at December 31, 2007 and 2006, respectively. These amounts are included in deferred debits and other assets - other on the accompanying consolidated balance sheets.

2. Short-Term Debt

Limits: The amount of short-term borrowings that may be incurred by PSNH is subject to periodic approval by either the NHPUC or FERC. Between January 1, 2007 and March 30, 2007, PSNH was authorized by the NHPUC to incur short-term borrowings up to $100 million. In an order dated March 30, 2007, the NHPUC authorized PSNH to incur short-term borrowings up to a maximum of 10 percent of net fixed plant plus an additional 3 percent through December 31, 2007. In an order dated August 3, 2007, the NHPUC increased the amount of authorized short-term borrowings to a maximum of 10 percent of net fixed plant plus a fixed amount of $35 million through December 31, 2008, or until PSNH has utilized its remaining long-term debt authorization. At December 31, 2007, this amount totaled $162.1 million. As a result of this NHPUC jurisdiction over short-term debt, PSNH is not currently require d to obtain FERC approval for its short-term borrowings.

Credit Agreement: PSNH, along with other NU subsidiaries, is a party to a five-year unsecured revolving credit facility which expires on November 6, 2010. PSNH can borrow up to $100 million on a short-term basis, or subject to regulatory approvals, on a long-term basis. At December 31, 2007, PSNH had $10 million in borrowings under this facility. At December 31, 2006, PSNH had no borrowings outstanding under this facility. The weighted-average interest rate on PSNH's notes payable to banks outstanding at December 31, 2007 was 7.25 percent.

Under this credit agreement, PSNH may borrow at variable rates plus an applicable margin based upon the higher of Standard and Poor's (S&P) or Moody's Investors Service (Moody's) credit ratings assigned to the borrower.

In addition, PSNH must comply with certain financial and non-financial covenants, including but not limited to, a consolidated debt to capitalization ratio. PSNH currently is and expects to remain in compliance with these covenants.

Amounts outstanding under this credit facility are classified as current liabilities as notes payable to banks on the accompanying consolidated balance sheet as management anticipates that all borrowings designated under this credit facility will be outstanding for no more than 364 days at one time.

Pool: PSNH is a member of the NU Money Pool (Pool). The Pool provides an efficient use of cash resources at NU and reduces outside short-term borrowings. NUSCO administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are first met with available funds of other member companies, including funds borrowed by NU. NU may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on external loans by NU, however, bear interest at NU's cost and must be repaid based upon the terms of NU's original borrowing. At December 31, 2007 and 2006, PSNH had borrowings of $11.3 million and $36.5 million from the Pool, respectively. The weighted-average int erest rate on borrowings from the Pool for the years ended December 31, 2007 and 2006 was 5.19 percent and 4.98 percent, respectively.

3. Derivative Instruments

For PSNH, except for existing interest rate swap agreements, offsetting regulatory assets or liabilities are recorded for the changes in fair value of their derivative contracts, as these contracts were part of operating costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates. The fair value of this company's derivative contracts may not represent amounts that will be realized.

PSNH has electricity procurement contracts that are derivatives. The fair value of these contracts is calculated based on market prices and is recorded as short-term derivative assets of $1.5 million and short-term derivative liabilities of $2.5 million at December 31, 2007. At December 31, 2006, the fair value was recorded as a short-term derivative liability of $28.4 million. An offsetting regulatory liability/asset was recorded as management believes that these costs will be refunded/recovered in rates as the energy is delivered.

In 2007, PSNH entered into a contract to assign transmission rights to a Hydro-Quebec direct current line in exchange for two energy call options which expire in 2010. These energy call options are derivatives that do not qualify for the normal purchases and sales exception and are accounted for at fair value based on market prices. At December 31, 2007, the options were recorded as a short-term derivative asset of $3.6 million and a long-term derivative asset of $12.1 million. An offsetting regulatory liability was recorded, as the benefit of this arrangement will be refunded to customers in rates.

At December 31, 2006, PSNH had a contract to purchase oil that was a derivative, the fair value of which was recorded as a short-term derivative liability of $10.8 million. An offsetting regulatory asset was recorded as management believes that this cost will be recovered in rates through a deferral mechanism that tracks generation revenues and costs. This contract expired in 2007.

In December of 2007, PSNH entered into a forward interest rate swap agreement to hedge the interest cash outflows associated with its proposed $110 million March of 2008 debt issuance. The interest rate swap is based on a 10-year LIBOR swap rate and matches the index used for the debt issuance. As a cash flow hedge at December 31, 2007, the fair value of the hedge was recorded as a $1 million short-term derivative asset on the consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

4. Employee Benefits

A. Pension Benefits and Postretirement Benefits Other Than Pensions

On December 31, 2006, PSNH implemented SFAS No. 158, which applies to NU’s Pension Plan, SERP, and PBOP Plan and required PSNH to record the funded status of these plans based on the projected benefit obligation for the Pension Plan and accumulated postretirement benefit obligation (APBO) for the PBOP Plan on the consolidated balance sheets at December 31, 2007 and 2006. SFAS No. 158 requires the additional liability to be recorded with an offset to accumulated other comprehensive income in common stockholders’ equity. This amount is remeasured annually, or as circumstances dictate. However, because PSNH is a cost-of-service, rate regulated entity under SFAS No. 71, regulatory assets were recorded in the amount of $50.4 million and $90.4 million at December 31, 2007 and 2006, respectively, as these benefits expense amounts have been and continue to be recoverable in cost-of-service, regulated rates. &nb sp;Regulatory accounting was also applied to the portions of the NUSCO costs that support PSNH, as these amounts are also recoverable.

Pension Benefits: PSNH participates in a uniform non-contributory defined benefit retirement plan (Pension Plan) covering substantially all regular PSNH employees. Benefits are based on years of service and the employees’ highest eligible compensation during 60 consecutive months of employment. PSNH uses a December 31st measurement date for the Pension Plan. Pension expense affecting earnings is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2007	2006	2005
Total pension expense	$ 19.5	$ 20.8	$ 19.2
Expense capitalized as utility plant	(4.8)	(4.8)	(4.9)
Total pension expense, net of amounts capitalized	$ 14.7	$ 16.0	$ 14.3

Total pension expense above includes a pension curtailment benefit of $0.7 million and expense of $1.1 million for the years ended December 31, 2006 and 2005, respectively. There were no pension curtailments or termination benefits in 2007.

Pension Curtailments and Termination Benefits: In December of 2005, a new program was approved allowing then current employees to elect to receive retirement benefits under a new 401(k) benefit rather than under the Pension Plan. The approval of the new plan resulted in recording an estimated pre-capitalization, pre-tax curtailment expense of $1.1 million in 2005, as a certain number of employees were expected to elect the new 401(k) benefit, resulting in a reduction in aggregate estimated future years of service under the Pension Plan. Because the predicted level of elections of the new benefit did not occur, PSNH recorded a pre-capitalization, pre-tax reduction in the curtailment expense of $0.7 million in 2006.

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 $5.5 million and was reflected as a prior service cost and as a decrease in the funded status of the Pension Plan. This amount will be amortized over a 12-year period representing average remaining service lives of employees.

Market-Related Value of Pension Plan Assets: PSNH bases the actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets and are included in actuarial gains and losses. Since the market-related valuation calculation recognizes gains or losses over a four-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

SERP: NU has maintained a SERP since 1987. The SERP provides its eligible participants, some of which are officers of PSNH, with benefits that would have been provided to them under NU's retirement plan if certain Internal Revenue Code (IRC) and other limitations were not imposed.

PBOP: PSNH provides certain health care benefits, primarily medical and dental, and life insurance benefits through a PBOP Plan. These benefits are available for employees retiring from PSNH 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. PSNH uses a December 31st measurement date for the PBOP Plan.

PSNH annually funds postretirement costs through external trusts with amounts that have been and will continue to be recovered in rates and that are tax deductible. Currently, there are no pending regulatory actions regarding postretirement benefit costs.

PBOP Curtailments and Termination Benefits: PSNH recorded a $0.1 million pre-tax curtailment expense at December 31, 2006 relating to its corporate reorganization. PSNH had no PBOP curtailments or termination benefits in 2007 or 2005.

The following table represents information on the plans' benefit obligation, fair value of plan assets, and funded status:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Change in benefit obligation						
Benefit obligation at beginning of year	$ (370.1)	$ (354.6)	$ (2.2)	$ (1.6)	$ (86.0)	$ (87.0)
Service cost	(9.6)	(9.6)	-	-	(1.7)	(1.8)
Interest cost	(21.7)	(20.3)	(0.1)	(0.1)	(4.8)	(5.0)
Actuarial gain/(loss)	28.9	6.3	0.4	(0.6)	3.3	1.8
Prior service cost	(5.5)	-	-	-	-	-
Benefits paid - excluding lump sum payments	16.6	15.7	0.1	0.1	6.9	6.5
Federal subsidy on benefits paid	-	-	-	-	(0.7)	(0.5)
Curtailment/impact of plan changes	-	(7.6)	-	-	-	-
Benefit obligation at end of year	$ (361.4)	$ (370.1)	$ (1.8)	$ (2.2)	$ (83.0)	$ (86.0)
Change in plan assets						
Fair value of plan assets at beginning of year	$ 219.5	$ 202.3	N/A	N/A	$ 49.5	$ 39.9
Actual return on plan assets	20.2	32.9	N/A	N/A	2.7	6.0
Employer contribution	-	-	N/A	N/A	8.6	10.1
Benefits paid - excluding lump sum payments	(16.6)	(15.7)	N/A	N/A	(6.9)	(6.5)
Fair value of plan assets at end of year	$ 223.1	$ 219.5	N/A	N/A	$ 53.9	$ 49.5
Funded status at December 31st	$ (138.3)	$ (150.6)	$ (1.8)	$ (2.2)	$ (29.1)	$ (36.5)

The amounts recognized on the accompanying consolidated balance sheets for the funded status above at December 31, 2007 and 2006 is as follows:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Accrued pension	$ (138.3)	$ (150.6)	$ -	$ -	$ -	$ -
Other deferred credits and other liabilities	-	-	(1.8)	(2.2)	-	-
Accrued postretirement benefits	-	-	-	-	(29.1)	(36.5)

In 2005, as a result of the expected transition of employees into the new 401(k) benefit and the company's corporate reorganization, NU reduced PSNH's share of the Pension Plan's obligation via a curtailment benefit related to the reduction in the future years of service expected to be rendered by plan participants. This overall reduction in plan obligation served to reduce the previously unrecognized actuarial losses. In 2006, $7.6 million of this curtailment was reversed because actual levels of elections of the new 401(k) benefit were much lower than expected and is reflected above as an increase to the obligation.

For the Pension Plan, the company amortizes its transition obligation over the remaining service lives of its employees as calculated for PSNH on an individual subsidiary basis and amortizes the prior service cost and unrecognized net actuarial loss over the remaining service lives of its employees as calculated on an NU consolidated basis. For the PBOP Plan, the company amortizes its transition obligation, prior service cost, and unrecognized net actuarial loss over the remaining service lives of its employees as calculated for PSNH on an individual subsidiary basis.

Although the SERP does not have any plan assets, benefit payments are supported by earnings on marketable securities held by NU.

The accumulated benefit obligation for the Pension Plan was $308.3 million and $317.8 million at December 31, 2007 and 2006, respectively, and $1.6 million and $1.9 million for the SERP at December 31, 2007 and 2006, respectively.

The following is a summary of amounts recorded as regulatory assets as a result of SFAS No. 158 at December 31, 2007 and 2006 and the changes in those amounts recorded during the years (millions of dollars):

	At December 31,					
	Pension		SERP		PBOP	
	2007	2006	2007	2006	2007	2006
Transition obligation at beginning of year	$ 0.9	$ -	$ -	$ -	$ 14.9	$ -
Amounts recorded upon adoption of SFAS No. 158	-	0.9	-	-	-	14.9
Amounts reclassified as net periodic benefit expense	(0.3)	-	-	-	(2.5)	-
Transition obligation at end of year	$ 0.6	$ 0.9	$ -	$ -	$ 12.4	$ 14.9
Prior service cost at beginning of year	$ 8.2	$ -	$ -	$ -	$ -	$ -
Amounts reclassified as net periodic benefit expense	(1.7)	-	-	-	-	-
Prior service cost arising during the year (1)	5.4	8.2	-	-	-	-
Prior service cost at end of year	$ 11.9	$ 8.2	$ -	$ -	$ -	$ -
Net actuarial losses at beginning of year	$ 44.2	$ -	$ 1.4	$ -	$ 20.8	$ -
Amounts reclassified as net periodic benefit expense	(4.0)	-	(0.2)	-	(2.3)	-
Actuarial (gains)/losses arising during the year (1)	(31.2)	44.2	(0.5)	1.4	(2.7)	20.8
Actuarial losses at end of year	$ 9.0	$ 44.2	$ 0.7	$ 1.4	$ 15.8	$ 20.8
Total deferred benefit costs as regulatory assets	$ 21.5	$ 53.3	$ 0.7	$ 1.4	$ 28.2	$ 35.7

(1) Amounts arising for prior service cost and actuarial (gains)/losses in 2006 relate to the initial adoption of SFAS No. 158.

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2008 are as follows (millions of dollars):

	Estimated Expense in 2008		
	Pension	SERP	PBOP
Transition obligation	$ 0.3	$ -	$ 2.5
Prior service cost	1.9	-	-
Net actuarial loss	1.6	0.1	1.6
Total	$ 3.8	$ 0.1	$ 4.1

The following actuarial assumptions were used in calculating the plans' year end funded status:

	At December 31,			
	Pension Benefits and SERP		Postretirement Benefits	
Balance Sheets	2007	2006	2007	2006
Discount rate	6.60 %	5.90 %	6.35 %	5.80 %
Compensation/progression rate	4.00 %	4.00 %	N/A	N/A
Health care cost trend rate	N/A	N/A	8.50 %	9.00 %

The components of net periodic expense are as follows:

	For the Years Ended December 31,								
	Pension Benefits			SERP Benefits			Postretirement Benefits		
(Millions of Dollars)	2007	2006	2005	2007	2006	2005	2007	2006	2005
Service cost	$ 9.6	$ 9.6	$ 8.8	$ -	$ -	$ -	$ 1.7	$ 1.8	$ 1.6
Interest cost	21.7	20.3	19.3	0.1	0.1	0.1	4.8	5.0	4.4
Expected return on plan assets	(17.8)	(16.3)	(16.6)	-	-	-	(3.4)	(2.5)	(2.1)
Net transition obligation cost	0.3	0.3	0.3	-	-	-	2.5	2.5	2.5
Prior service cost	1.7	1.4	1.5	-	-	-	-	-	-
Actuarial loss	4.0	6.2	4.8	0.3	0.1	-	2.3	3.2	3.0
Net periodic expense before curtailments	19.5	21.5	18.1	0.4	0.2	0.1	7.9	10.0	9.4
Curtailment (benefit)/expense	-	(0.7)	1.1	-	-	-	-	0.1	-
Total - net periodic expense	$ 19.5	$ 20.8	$ 19.2	$ 0.4	$ 0.2	$ 0.1	$ 7.9	$ 10.1	$ 9.4

Not included in the pension expense above are amounts related to certain intercompany allocations totaling $1.6 million, $1.8 million and $2.2 million for the years ended December 31, 2007, 2006 and 2005, respectively, including pension curtailments and termination benefits benefit of $0.3 million in 2006 and expense of $0.6 million in 2005. Excluded from postretirement benefits expense are related intercompany allocations of $1.3 million, $1.4 million and $1.5 million for the years ended December 31, 2007, 2006 and 2005, respectively, including curtailments and termination benefits benefit of $0.1 million and expense of $0.2 million for the years ended December 31, 2006 and 2005, respectively. Excluded from SERP expense are related intercompany allocations of $0.4 million, $0.5 million and $0.4 million for the years ended December 31, 2007, 2006 and 2005, respectively. These amounts are included in other op erating expenses on the accompanying consolidated statements of income.

The following assumptions were used to calculate pension and postretirement benefit expense amounts:

Statements of Income	For the Years Ended December 31,					
	Pension Benefits and SERP			Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
Discount rate	5.95 % (1)	5.80 %	6.00 %	5.80 %	5.65 %	5.50 %
Expected long-term rate of return	8.75 %	8.75 %	8.75 %	N/A	N/A	N/A
Compensation/progression rate	4.00 %	4.00 %	4.00 %	N/A	N/A	N/A
Expected long-term rate of return -						
Health assets, net of tax	N/A	N/A	N/A	6.85 %	6.85 %	6.85 %
Life assets and non-taxable health assets	N/A	N/A	N/A	8.75 %	8.75 %	8.75 %

(1) The 2007 discount rate for the SERP was 5.9 percent.

The following table represents the PBOP assumed health care cost trend rate for the next year and the assumed ultimate trend rate:

	Year Following December 31,	
	2007	2006
Health care cost trend rate assumed for next year	8.50 %	9.00 %
Rate to which health care cost trend rate is assumed to decline (the ultimate trend rate)	5.00 %	5.00 %
Year that the rate reaches the ultimate trend rate	2015	2011

At December 31, 2007, the health care cost trend assumption was reset for 2008 at 8.5 percent, decreasing one half percentage point per year to an ultimate rate of 5 percent in 2015.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point in each year would have the following effects:

(Millions of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Effect on total service and interest cost components	$ 0.2	$ (0.2)
Effect on postretirement benefit obligation	$ 2.9	$ (2.5)

NU's investment strategy for its Pension Plan and PBOP Plan is to maximize the long-term rate of return on those plans' assets within an acceptable level of risk. The investment strategy establishes target allocations, which are routinely reviewed and periodically rebalanced. NU's expected long-term rates of return on Pension Plan assets and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, NU also evaluated input from actuaries and consultants, as well as long-term inflation assumptions and NU's historical 25-year compounded return of approximately 11.8 percent. The Pension Plan's and PBOP Plan's target asset allocation assumptions and expected long-term rate of return assumptions by asset category are as follo ws:

	At December 31,					
	Pension Benefits				Postretirement Benefits	
	2007		2006		2007 and 2006	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:						
United States	40%	9.25%	45%	9.25%	55%	9.25%
Non-United States	17%	9.25%	14%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	3%	10.25%	2%	10.25%
Private	8%	14.25%	8%	14.25%	-	-
Debt Securities:						
Fixed income	25%	5.50%	20%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%	5%	7.50%
Real Estate	5%	7.50%	5%	7.50%	-	-

The actual asset allocations at December 31, 2007 and 2006 approximated these target asset allocations. The plans' actual weighted-average asset allocations by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
Asset Category	**2007**	**2006**	**2007**	**2006**
Equity Securities:				
United States	40%	46%	55%	54%
Non-United States	17%	16%	14%	14%
Emerging markets	5%	4%	1%	1%
Private	7%	5%	-	-
Debt Securities:				
Fixed income	26%	19%	29%	29%
High yield fixed income	-	5%	1%	2%
Real Estate	5%	5%	-	-
Totals	100%	100%	100%	100%

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid/(received) for the Pension, SERP, and PBOP Plans:

(Millions of Dollars)

Year	Pension Benefits	SERP Benefits	Postretirement Benefits	Government Benefits
2008	$ 16.8	$ 0.1	$ 7.2	$ (0.6)
2009	18.3	0.1	7.4	(0.6)
2010	19.2	0.1	7.6	(0.7)
2011	20.3	0.1	7.7	(0.7)
2012	21.4	0.1	7.8	(0.8)
2013-2017	129.5	0.8	40.2	(5.0)

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, PSNH's policy is to annually fund the Pension Plan in an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and IRC. PSNH does not expect to make any contributions to the Pension Plan in 2008. For the PBOP Plan, it is currently PSNH's policy to annually fund an amount equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits. PSNH contributed $8.1 million for the year ended December 31, 2007 to fund the PBOP Plan and expects to make $6.9 million in contributions to the PBOP Plan in 2008. Beginning in 2007, PSNH made additional contributions to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $0.5 million in 2007 and is estimated to be $0.6 million for 2008.

B. Defined Contribution Plans

NU maintains a 401(k) Savings Plan for substantially all PSNH employees. This savings plan provides for employee contributions up to specified limits. NU matches employee contributions up to a maximum of three percent of eligible compensation with one percent in cash and two percent in NU common shares. The 401(k) matching contributions of cash and NU common shares made by NU to PSNH employees were $2.2 million in 2007, $2.1 million in 2006 and $2 million in 2005.

Effective on January 1, 2006, all newly hired, non-bargaining unit employees, and effective on January 1, 2007 or as subject to collective bargaining agreements, certain newly hired PSNH bargaining unit employees participate in a new defined contribution savings plan called the K-Vantage benefit. These employees are not eligible to participate in the existing defined benefit Pension Plan. In addition, participants in the Pension Plan at January 1, 2006 were given the opportunity to choose to become a participant in the K-Vantage benefit beginning in 2007, in which case their benefit under the Pension Plan would be frozen. NU makes contributions to the K-Vantage benefit based on a percentage of participants' eligible compensation, as defined by the benefit document. The contributions made by NU to PSNH employees were $139 thousand and $23 thousand in 2007 and 2006, respectively.

C. Share-Based Payments

NU maintains an Employee Stock Purchase Plan (ESPP) and other long-term equity-based incentive plans under the Northeast Utilities Incentive Plan (Incentive Plan) in which PSNH employees and officers are entitled to participate. PSNH records compensation cost related to these plans, as applicable, for shares issued or sold to PSNH employees and officers, as well as the allocation of costs associated with shares issued or sold to NUSCO employees and officers that support PSNH. 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 PSNH's net income.

SFAS No. 123(R) requires that share-based payments be recorded using the fair value-based method based on the fair value at the date of grant and applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed. For prior periods, as permitted by SFAS No. 123, "Accounting for Stock-Based

Compensation," and related guidance, NU used the intrinsic value method and disclosed the pro forma effects as if NU recorded equity-based compensation under the fair value-based method.

Under SFAS No. 123(R), NU accounts for its various share-based plans as follows:

- For grants of restricted shares and restricted share units (RSUs), NU records compensation expense over the vesting period based upon the fair value of NU's common shares at the date of grant but records this expense net of estimated forfeitures.

- Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.

- NU has not granted any stock options to PSNH employees or officers 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 in which PSNH participates, NU is authorized to grant up to 4.5 million new shares for various types of awards, including restricted shares, RSUs, performance units and stock options to eligible employees and board members. At December 31, 2007 and 2006, NU had 3,055,083 and 570,494 of common shares, respectively, available for issuance under the Incentive Plan.

Restricted Shares and RSUs: NU has granted restricted shares under the 2002 through 2004 incentive programs that are subject to three-year and four-year graded vesting schedules. NU has granted RSUs under the 2004 through 2007 incentive programs that are subject to three-year and four-year graded vesting schedules. RSUs are paid in shares, including amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of total NU restricted share and RSU transactions for the year ended December 31, 2007 is as follows:

Restricted Shares	Restricted Shares	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	65,674	$15.00			
Granted	-	-			
Vested	(59,424)	$14.14	$0.8		
Outstanding at December 31, 2007	6,250	$18.65	$0.1	$ -	0.2

The per share and total weighted average grant date fair value for restricted shares vested was $14.52 and $1.1 million, respectively, for the year ended December 31, 2006 and $14.60 and $1.4 million, respectively, for the year ended December 31, 2005.

The total compensation cost recognized by PSNH for its portion of the restricted shares above was approximately $8 thousand, net of taxes of approximately $5 thousand for the year ended December 31, 2007, approximately $90 thousand, net of taxes of approximately $60 thousand for the year ended December 31, 2006, and approximately $100 thousand, net of taxes of approximately $65 thousand for the year ended December 31, 2005.

RSUs	RSUs (Units)	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	715,299	$19.41			
Granted	330,785	$28.83	$ 9.5		
Issued	(161,137)	$19.77	$ 3.2		
Forfeited	(53,947)	$20.16	$ 1.1		
Outstanding at December 31, 2007	831,000	$22.99	$19.1	$7.7	1.8

The per share and total weighted average grant date fair value for RSUs granted was $19.87 and $7.4 million, respectively, for the year ended December 31, 2006 and $18.89 and $5.8 million, respectively, for the year ended December 31, 2005. The weighted average grant date fair value per share for RSUs issued was $18.50 and $19.06 for the years ended December 31, 2006 and 2005, respectively. The total weighted average fair value of RSUs issued was $2.2 million and $1.9 million for the years ended December 31, 2006 and 2005, respectively.

The compensation cost recognized by PSNH for its portion of the RSUs above was approximately $586 thousand, net of taxes of approximately $391 thousand for the year ended December 31, 2007, approximately $440 thousand, net of taxes of approximately $290 thousand for the year ended December 31, 2006 and approximately $230 thousand, net of taxes of approximately $150 thousand for the year ended December 31, 2005.

Stock Options: Prior to 2003, NU granted stock options to certain PSNH employees. These options were fully vested as of December 31, 2005, and no compensation expense was recorded as a result of the adoption of SFAS No. 123(R). The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model.

5. Commitments and Contingencies

A. Environmental Matters

General: PSNH 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, PSNH 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 PSNH's responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

The amounts recorded as environmental liabilities on the consolidated balance sheets represent management’s best estimate of the liability for environmental costs, if reasonably estimable, and take into consideration site assessment and remediation costs. Based on currently available information for estimated site assessment and remediation costs at December 31, 2007 and 2006, PSNH had $5.5 million and $5.6 million, respectively, recorded as environmental reserves. A reconciliation of the activity in these reserves at December 31, 2007 and 2006 is as follows:

	For the Years Ended December 31,	
(Millions of Dollars)	**2007**	**2006**
Balance at beginning of year	$ 5.6	$ 6.2
Additions and adjustments	0.2	-
Payments and adjustments	(0.3)	(0.6)
Balance at end of year	$ 5.5	$ 5.6

Of the 17 sites PSNH has currently included in the environmental reserve, 11 sites are in the remediation or long-term monitoring phase, two sites have had some level of site assessments completed, and the remaining four sites are in the preliminary stages of site assessment.

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

At December 31, 2007, in addition to the 17 sites, there were two sites for which there are unasserted claims; however, any related site assessment or remediation costs are not probable or estimable at this time. PSNH’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.

MGP Sites: Manufactured Gas Plant (MGP) sites comprise the largest portion of PSNH’s environmental liability. MGPs are sites that manufactured gas from coal which produced certain byproducts that may pose a risk to human health and the environment. At December 31, 2007 and 2006, $4.7 million and $4.9 million, respectively, represent amounts for the site assessment and remediation of MGPs. At December 31, 2007 and 2006, PSNH's two largest MGP sites comprise approximately 94 percent and 91 percent, respectively, of the total MGP environmental liability.

For two MGP 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 the company to estimate the range of losses for environmental costs. At December 31, 2007, $0.8 million had been accrued as a liability for these sites, which represents management’s best estimate of the liability for environmental costs. This amount differs from an estimated range of loss from zero to $4.3 million. For the 15 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 17 sites, three are superfund sites under CERCLA for which PSNH has been notified that it is a potentially responsible party but for which the site assessment and remediation are not being managed by PSNH. At December 31, 2007, a liability of $0.3 million accrued on these sites represents PSNH's estimates of its potential remediation costs with respect to these three 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 has a rate recovery mechanism for environmental costs.

B. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of PSNH's significant long-term contractual arrangements at December 31, 2007 are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Totals
VYNPC	$ 7.0	$ 7.6	$ 7.3	$ 7.5	$ 1.8	$ -	$ 31.2
Electricity procurement obligations	52.6	55.4	56.0	33.6	32.5	199.4	429.5
Wood, coal and transportation contracts	132.2	88.7	83.5	73.9	47.4	-	425.7
PNGTS pipeline commitments	2.0	2.0	2.0	2.0	2.0	9.9	19.9
Hydro-Quebec	6.6	6.5	6.5	6.6	6.6	52.7	85.5
Transmission segment project commitments	49.0	-	-	-	-	-	49.0
Yankee Companies billings	5.6	4.0	4.1	3.0	3.1	8.4	28.2
Generation segment project commitments	11.8	9.0	5.0	4.0	2.0	1.0	32.8
Totals	$ 266.8	$ 173.2	$ 164.4	$ 130.6	$ 95.4	$ 271.4	$ 1,101.8

VYNPC: PSNH has a commitment to buy approximately 4 percent of the Vermont Yankee Nuclear Power Corporation (VYNPC) plant's output through March of 2012 at a range of fixed prices. The total cost of purchases under contracts with VYNPC amounted to $6.4 million in 2007, $8.1 million in 2006 and $6.4 million in 2005.

Electricity Procurement Obligations: PSNH has entered into various IPP contracts that extend through 2023 for the purchase of electricity. The total cost of purchases and obligations under these contracts amounted to $72.9 million in 2007, $123.6 million in 2006 and $125.3 million in 2005. The majority of the contracts expire by 2018.

Wood, Coal and Transportation Contracts: PSNH has entered into various arrangements for the purchase of wood, coal and the transportation services for fuel supply for its electric generating assets in 2008. PSNH's fuel and natural gas costs, excluding emissions allowances, amounted to approximately $183.8 million in 2007, $149.1 million in 2006 and $193.4 million in 2005.

PNGTS Pipeline Commitments: PSNH has a contract for capacity on the Portland Natural Gas Transmission System *(*PNGTS) pipeline which extends through 2018. The total cost under this contract amounted to $3.1 million in 2007, $1.4 million in 2006 and $1.6 million in 2005. These costs are not recovered from PSNH's retail customers.

Hydro-Quebec: Along with other New England utilities, PSNH has entered into an agreement to support transmission and terminal facilities which were built to import electricity from the Hydro-Quebec system in Canada. PSNH is obligated to pay, over a 30-year period ending in 2020, its proportionate share of the annual O&M expenses and capital costs of those facilities. The total cost of this agreement amounted to $5.8 million in 2007, $6.4 million in 2006 and $6.6 million in 2005.

Transmission Segment Project Commitments: These amounts represent commitments for various services and materials associated with PSNH's transmission projects.

Yankee Companies Billings: PSNH 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 PSNH. PSNH in turn recovers these costs from its customers through NHPUC-approved retail rates. The table of estimated future annual costs includes the estimated decommissioning and closure costs for CYAPC, MYAPC and YAEC.

See Note 5C, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements for information regarding the collection of the Yankee Companies' decommissioning costs.

Generation Segment Project Commitments: These amounts represent commitments for engineering and program management services associated with PSNH's coal-fired 440 megawatt Merrimack Station clean air project, which also includes the addition of a wet scrubber to reduce mercury and sulfur dioxide emissions at Merrimack Station Units 1 and 2. The total cost under these contracts amounted to $1.9 million in 2007 and $0.9 million in 2006.

C. Deferred Contractual Obligations

PSNH has significant decommissioning and plant closure cost obligations to the Yankee Companies, which have completed the physical decommissioning of all three of their facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including PSNH. PSNH in turn recovers these costs through NHPUC-approved retail rates. PSNH's ownership interest in the Yankee Companies at December 31, 2007 is 5 percent of CYAPC, 7 percent of YAEC and 5 percent of MYAPC.

PSNH's percentage share of the obligation to support the Yankee Companies under FERC-approved rate tariffs is the same as the ownership percentages above.

CYAPC: Under the terms of the settlement agreement between CYAPC, the Connecticut Department of Public Utility Control (DPUC), the Connecticut Office of Consumer Counsel, and Maine regulators, the parties agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars). Annual collections began in January of 2007, and were reduced from the $93 million originally requested for years 2007 through 2010 to lower levels ranging from $37 million in 2007 rising to $46 million in 2015. The reduction to annual collections was achieved by extending the collection period by 5 years through 2015 by reflecting the proceeds from a settlement agreement with Bechtel Power Corporation, by reducing collections in 2007, 2008 and 2009 by $5 million per year, and making other adjustments. PSNH has recovered its share of these costs from its customers.

YAEC: On July 31, 2006, the FERC approved a settlement agreement with the DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service previously filed by YAEC. This settlement agreement did not materially affect the level of 2006 charges. Under the settlement agreement, YAEC agreed to revise its November 2005 decommissioning cost increase from $85 million to $79 million. Other terms of the settlement agreement include extending the collection period for charges through December 2014, reconciling and adjusting future charges based on actual decontamination and decommissioning expenses. PSNH has recovered its share of these costs from its customers.

MYAPC: MYAPC is collecting revenues from PSNH and other owners that are adequate to recover the remaining cost of decommissioning its plant. PSNH has recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same periods as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related to disallowed spent nuclear fuel pool operating expenses.

The Court of Federal Claims, following precedent set in another case, did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. In December of 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December of 2006, the DOE appealed the ruling, and the Yankee Companies filed a cross-appeal. The refund to PSNH of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. The appeal is expected to be argued in 2008 with a decision from the Court of Appeals to follow.

PSNH's aggregate share of these damages is $7.8 million. PSNH cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, PSNH 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.

D. Guarantees

NU provides credit assurances on behalf of subsidiaries, including PSNH, in the form of guarantees and letters of credit (LOCs) in the normal course of business. At December 31, 2007, the maximum level of exposure in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," under guarantees by NU on behalf of PSNH totaled $3.5 million. A majority of these guarantees do not have established expiration dates, and some guarantees have unlimited exposure to commodity price movements. Additionally, NU had $19 million of LOCs issued on behalf of PSNH at December 31, 2007. PSNH has no guarantees of the performance of third parties.

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.

E. Transmission Rate Matters and FERC Regulatory Issues

As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (FERC ROE decision), PSNH recorded an estimated regulatory liability for refunds of $5 million as of December 31, 2006. In 2007, PSNH completed the customer refunds that were calculated in accordance with the compliance filing required by the FERC ROE decision and refunded approximately $4.5 million to regional, local and localized transmission customers. The $0.5 million positive pre-tax difference ($0.3 million after-tax) between the estimated regulatory liability recorded and the actual amount refunded was recognized in earnings in 2007.

Pursuant to the October 31, 2006 FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. On August 27, 2007, NU, on behalf of PSNH, and the other New England transmission owners submitted a revised compliance filing, which outlined the regional refund process to comply with the FERC's July 26, 2007 order. In addition, the transmission owners filed a request for rehearing claiming that the FERC improperly set the floor for refunds based on the lower rates that the FERC app roved in its October 31, 2006 order, rather than the last approved rates, for the period from June 3, 2005 to September 3, 2006. The FERC denied this request on January 17, 2008, and the transmission owners have until March 17, 2008 to appeal, if they so choose.

PSNH's transmission segment refunded approximately $0.4 million of revenues and interest related to the July 26, 2007 order (approximately $0.3 million after-tax), which was recorded in 2007. PSNH's distribution segment received approximately $0.4 million of revenues and interest related to the July 26, 2007 order (approximately $0.3 million after-tax), which was recorded in 2007.

F. Other Litigation and Legal Proceedings

PSNH is involved in other legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, some of which involve management's best estimate of probable loss as defined by SFAS No. 5. The company records and discloses losses when these losses are probable and reasonably estimable in accordance with SFAS No. 5, discloses matters when losses are probable but not estimable, and expenses legal costs related to the defense of loss contingencies as incurred.

6. 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 Special Deposits: The carrying amounts approximate fair value due to the short-term nature of these cash items.

Long-Term Debt and Rate Reduction Bonds: The fair value of PSNH's fixed-rate securities is based upon quoted market prices for those issues or similar issues. Adjustable rate securities are assumed to have a fair value equal to their carrying value. The carrying amounts of PSNH's financial instruments and the estimated fair values are as follows:

	At December 31, 2007	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**
Long-term debt -		
First mortgage bonds	$ 170.0	$ 164.6
Other long-term debt	407.3	420.6
Rate reduction bonds	282.0	297.3

	At December 31, 2006	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**
Long-term debt -		
First mortgage bonds	$ 100.0	$ 96.4
Other long-term debt	407.3	421.7
Rate reduction bonds	333.8	347.9

Other Financial Instruments: The carrying value of other financial instruments included in current assets and current liabilities approximates their fair value due to the short-term nature of these instruments.

7. Leases

PSNH has entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, and office space. In addition, PSNH incurs costs associated with leases entered into by NUSCO and Rocky River Realty. These costs are included below in operating lease payments charged to expense and amounts capitalized as well as future operating lease payments for 2008 through 2012 and thereafter. 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 $0.4 million in 2007, 2006 and 2005. Interest included in capital lease rental payments was $0.2 million in 2007, 2006 and 2005. Capital lease asset amortization was $0.2 million in 2007, 2006 and 2005.

Operating lease rental payments charged to expense were $3.5 million in 2007, and $4.1 million in both 2006 and 2005. The capitalized portion of operating lease payments was approximately $2 million, $1.9 million and $1.8 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Future minimum rental payments excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, at December 31, 2007 are as follows:

(Millions of Dollars)	Capital Leases	Operating Leases
2008	$ 0.3	$ 6.0
2009	0.1	5.2
2010	0.1	4.4
2011	0.2	3.5
2012	0.2	2.6
Thereafter	0.6	8.2
Future minimum lease payments	1.5	$ 29.9
Less amount representing interest	(0.4)	
Present value of future minimum lease payments	$ 1.1	

8. Dividend Restrictions

The Federal Power Act limits the payment of dividends by PSNH to its retained earnings balance 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 PSNH. PSNH also has a revolving credit agreement that imposes a leverage restriction tied to its ratio of consolidated total debt to total capitalization. Approximately $11 million of PSNH's retained earnings is subject to restriction under its FERC hydroelectric license conditions.

9. Accumulated Other Comprehensive Income

The accumulated balance for each other comprehensive income/(loss), net of tax, item is as follows:

(*Millions of Dollars*)	December 31, 2006	Current Period Change	December 31, 2007
Qualified cash flow hedging instruments	$ -	$ 0.6	$ 0.6
Unrealized gains on securities	0.2	-	0.2
Accumulated other comprehensive income	$ 0.2	$ 0.6	$ 0.8

(Millions of Dollars)	December 31, 2005	Current Period Change	December 31, 2006
Unrealized gains on securities	$ 0.2	$ -	$ 0.2
Minimum SERP liability	(0.1)	0.1	-
Accumulated other comprehensive income	$ 0.1	$ 0.1	$ 0.2

The changes in the components of other comprehensive income/(loss) are reported net of the following income tax effects:

(Millions of Dollars)	2007	2006	2005
Qualified cash flow hedging instruments	$ 0.4	$ -	$ -
Minimum SERP liability	-	-	(0.1)
Accumulated other comprehensive income/(loss)	$ 0.4	$ -	$ (0.1)

The unrealized gains on securities above relate to $4 million and $3.8 million of SERP securities at December 31, 2007 and 2006, respectively. The fair value of these securities is included in prepayments and other on the accompanying consolidated balance sheets.

Fair value adjustments included in accumulated other comprehensive income for PSNH's qualified cash flow hedging instruments are as follows:

(Millions of Dollars, Net of Tax)	At December 31, 2007
Balance at beginning of year	$ -
Cash flow transactions entered into for the period	0.6
Total fair value adjustments included in accumulated other comprehensive income	$ 0.6

In December of 2007, PSNH entered into a forward interest rate swap agreement associated with its planned 2008 long-term debt issuance. As a result, $0.6 million, net of tax, was recorded in accumulated other comprehensive income with a corresponding pre-tax offset to derivative assets for the fair value of the derivative instrument as of December 31, 2007. For further information, see Note 3, "Derivative Instruments," to the consolidated financial statements.

Management cannot estimate the amount that will be reclassified from accumulated other comprehensive income to earnings over the next 12 months as it will be impacted by the settlement of the forward interest rate swap agreement.

10. Long-Term Debt

Details of long-term debt outstanding are as follows:

	At December 31,	
	2007	**2006**
	(Millions of Dollars)	
First Mortgage Bonds:		
5.25% Series L, due 2014	$ 50.0	$ 50.0
5.60% Series M, due 2035	50.0	50.0
6.15% Series N, due 2017	70.0	-
Total First Mortgage Bonds	$ 170.0	$ 100.0
Pollution Control Revenue Bonds:		
6.00% Tax-Exempt, Series D, due 2021	75.0	75.0
6.00% Tax-Exempt, Series E, due 2021	44.8	44.8
Adjustable Rate, Series A, due 2021	89.3	89.3
4.75% Tax-Exempt, Series B, due 2021	89.3	89.3
5.45% Tax-Exempt, Series C, due 2021	108.9	108.9
Total Pollution Control Revenue Bonds	$ 407.3	$ 407.3
Less amounts due within a year	-	-
Unamortized premiums and discounts, net	(0.3)	(0.2)
Long-term debt	$ 577.0	$ 507.1

There are no cash sinking fund requirements or debt maturities for the years 2008 through 2012. 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.

On September 24, 2007, PSNH issued $70 million of first mortgage bonds with a coupon rate of 6.15 percent and a maturity date of September 1, 2017. The proceeds were used to refinance the company's short-term borrowings, which were previously incurred to fund transmission and distribution capital expenditures.

Essentially all utility plant of PSNH is subject to the liens of the company's first mortgage bond indenture.

PSNH has $89.3 million of MBIA-insured tax-exempt Pollution Control Revenue Bonds (PCRBs) that are remarketed in an auction rate mode every 35 days.

PSNH entered into financing arrangements with the Business Finance Authority (BFA) of the state of New Hampshire, pursuant to which the BFA issued five series of PCRBs and loaned the proceeds to PSNH. At both December 31, 2007 and 2006, $407.3 million of the PCRBs were outstanding. PSNH’s obligation to repay each series of PCRBs is secured by first mortgage bonds and bond insurance as it applies to the 2001 Series A, B and C. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. For financial reporting purposes, these first mortgage bonds would not be considered outstanding unless PSNH failed to meet its obligations under the PCRBs.

The weighted average effective interest rate on PSNH's Series A variable-rate pollution control notes was 3.87 percent for 2007 and 3.50 percent for 2006.

PSNH's long-term debt agreements provide that it must comply with certain financial and non-financial covenants as are customarily included in such agreements. PSNH currently is and expects to remain in compliance with these covenants.

11. Segment Information

Segment information related to the distribution (including generation) and transmission segments for PSNH for the years ended December 31, 2007, 2006 and 2005 is as follows:

	For the Year Ended December 31, 2007		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues (2)	$ 1,036.5	$ 46.6	$ 1,083.1
Depreciation and amortization	(107.3)	(5.8)	(113.1)
Other operating expenses	(832.3)	(20.9)	(853.2)
Operating income	96.9	19.9	116.8
Interest expense, net of AFUDC	(42.0)	(4.3)	(46.3)
Interest income	1.5	0.6	2.1
Other income, net	3.5	1.1	4.6
Income tax expense	(16.2)	(6.6)	(22.8)
Net income	$ 43.7	$ 10.7	$ 54.4
Total assets (3)	$ 2,107.0	$ -	$ 2,107.0
Cash flows for total investments in plant (4)	$ 100.1	$ 67.6	$ 167.7

	For the Year Ended December 31, 2006		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues (2)	$ 1,100.1	$ 40.8	$ 1,140.9
Depreciation and amortization	(147.1)	(5.2)	(152.3)
Other operating expenses	(856.2)	(19.5)	(875.7)
Operating income	96.8	16.1	112.9
Interest expense, net of AFUDC	(42.4)	(3.3)	(45.7)
Interest income	1.1	-	1.1
Other income, net	5.7	0.5	6.2
Income tax expense	(34.2)	(5.0)	(39.2)
Net income	$ 27.0	$ 8.3	$ 35.3
Total assets (3)	$ 2,071.3	$ -	$ 2,071.3
Cash flows for total investments in plant (4)	$ 92.3	$ 34.4	$ 126.7

	For the Year Ended December 31, 2005		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues (2)	$ 1,091.9	$ 36.5	$ 1,128.4
Depreciation and amortization	(233.7)	(4.3)	(238.0)
Other operating expenses	(778.0)	(17.4)	(795.4)
Operating income	80.2	14.8	95.0
Interest expense, net of AFUDC	(43.9)	(2.4)	(46.3)
Interest income	0.3	0.1	0.4
Other income/(loss), net	5.1	(0.3)	4.8
Income tax expense	(7.8)	(4.4)	(12.2)
Net income	$ 33.9	$ 7.8	$ 41.7
Cash flows for total investments in plant (4)	$ 131.9	$ 26.9	$ 158.8

(1) Includes generation activities.

(2) PSNH revenues are primarily derived from residential, commercial and industrial customers and are not dependent on any single customer.

(3) Information for segmenting total assets between distribution and transmission is not available at December 31, 2007 and 2006. The distribution and transmission assets are disclosed in the distribution columns above.

(4) Cash flows for total investment in plant included in the segment information above are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income.

Consolidated Quarterly Financial Data (Unaudited)

(Thousands of Dollars)	Quarter Ended March 31,	June 30,	September 30,	December 31,
2007				
Operating Revenues	$ 277,096	$ 250,233	$ 284,326	$ 271,417
Operating Income	24,077	31,568	32,666	28,520
Net Income	9,967	15,245	13,016	16,206
2006				
Operating Revenues	$ 315,316	$ 294,638	$ 265,779	$ 265,167
Operating Income	20,001	41,264	28,066	23,554
Net Income	5,132	14,904	7,890	7,397

Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2007	2006	2005	2004	2003
Operating Revenues	$ 1,083,072	$ 1,140,900	$ 1,128,427	$ 968,749	$ 888,186
Net Income	54,434	35,323	41,739	46,641	45,624
Cash Dividends on Common Stock	30,720	41,741	42,383	27,186	16,800
Property, Plant and Equipment, net (a)	1,388,405	1,242,378	1,155,423	1,031,703	925,592
Total Assets	2,106,969	2,071,276	2,294,583	2,205,374	2,171,181
Rate Reduction Bonds	282,018	333,831	382,692	428,769	472,222
Long-Term Debt (b)	576,997	507,099	507,086	457,190	407,285
Obligations Under Capital Leases (b)	1,141	1,356	498	712	986

(a) Amount includes construction work in progress.

(b) Includes portions due within one year, but excludes rate reduction bonds.

Selected Consolidated Sales Statistics
(Unaudited)

	2007	2006	2005	2004	2003
Revenues: *(Thousands)*					
Residential	$ 457,616	$ 467,517	$ 450,230	$ 384,667	$ 351,622
Commercial	413,196	439,828	423,884	361,603	318,081
Industrial	156,258	166,132	190,299	175,921	159,560
Other Utilities	25,030	52,255	34,688	19,712	38,622
Streetlighting and Railroads	6,018	5,729	5,685	5,297	4,801
Miscellaneous	24,954	9,439	23,641	21,549	15,500
Total	$ 1,083,072	$ 1,140,900	$ 1,128,427	$ 968,749	$ 888,186
Sales: *(KWH - Millions)*					
Residential	3,176	3,087	3,162	3,015	2,944
Commercial	3,403	3,342	3,342	3,235	3,100
Industrial	1,528	1,582	1,612	1,716	1,684
Other Utilities	105	985	501	242	674
Streetlighting and Railroads	24	23	24	25	23
Total	8,236	9,019	8,641	8,233	8,425
Customers: *(Average)*					
Residential	417,420	413,980	408,959	403,088	388,133
Commercial	70,341	69,528	68,232	66,572	63,324
Industrial	2,770	2,761	2,768	2,783	2,758
Other	602	592	600	572	554
Total	491,133	486,861	480,559	473,015	454,769

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT

	State of Incorporation
Northeast Utilities (a Massachusetts business trust)	MA
The Connecticut Light and Power Company	CT
CL&P Funding LLC	DE
CL&P Receivables Corporation	CT
Holyoke Water Power Company	MA
Holyoke Power and Electric Company	MA
North Atlantic Energy Corporation	NH
North Atlantic Energy Service Corporation	NH
Northeast Nuclear Energy Company	CT
Northeast Utilities Service Company	CT
NU Enterprises, Inc.	CT
Northeast Generation Services Company	CT
E. S. Boulos Company	CT
Select Energy, Inc.	CT
Public Service Company of New Hampshire	NH
PSNH Funding LLC	DE
PSNH Funding LLC 2	DE
The Quinnehtuk Company	MA
The Rocky River Realty Company	CT
Western Massachusetts Electric Company	MA
WMECO Funding LLC	DE
Yankee Energy System, Inc.	CT
Yankee Gas Services Company	CT

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-141425 on Form S-3 and 333-63144, 333-121364 and 333-142724 on Forms S-8 of our reports dated February 28, 2008, relating to the consolidated financial statements and the effectiveness of internal control over financial reporting of Northeast Utilities as of December 31, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, as of January 1, 2007) and the related consolidated financial statement schedules appearing in and incorporated by reference in the Annual Report on Form 10-K of Northeast Utilities for the year ended December 31, 2007.

We consent to the incorporation by reference in Registration Statement No. 333-141425 on Form S-3 of our reports dated February 28, 2008, relating to the consolidated financial statements of The Connecticut Light and Power Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company (which reports express unqualified opinions and include explanatory paragraphs regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109*, as of January 1, 2007) and the related consolidated financial statement schedules appearing in and incorporated by reference in the Annual Report on Forms 10-K of The Connecticut Light and Power Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
February 28, 2008

Exhibit 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Charles W. Shivery, certify that:

1. I have reviewed this Annual Report on Form 10-K of Northeast Utilities (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ Charles W. Shivery
(Signature)
Charles W. Shivery
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Northeast Utilities (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Leon J. Olivier, certify that:

1. I have reviewed this Annual Report on Form 10-K of The Connecticut Light and Power Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ Leon J. Olivier
(Signature)
Leon J. Olivier
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of The Connecticut Light and Power Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Leon J. Olivier, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Hampshire (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ Leon J. Olivier
(Signature)
Leon J. Olivier
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Hampshire (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Leon J. Olivier, certify that:

1. I have reviewed this Annual Report on Form 10-K of Western Massachusetts Electric Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ Leon J. Olivier
(Signature)
Leon J. Olivier
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Western Massachusetts Electric Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Northeast Utilities (the registrant) on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission (the Report), we, Charles W. Shivery, Chairman, President and Chief Executive Officer of the registrant and David R. McHale, Senior Vice President and Chief Financial Officer of the registrant, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Charles W. Shivery
(Signature)
Charles W. Shivery
Chairman, President and Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

Date: February 28, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of The Connecticut Light and Power Company (the registrant) on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission (the Report), we, Leon J. Olivier, Chief Executive Officer of the registrant and David R. McHale, Senior Vice President and Chief Financial Officer of the registrant, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Leon J. Olivier
(Signature)
Leon J. Olivier
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

Date: February 28, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Public Service Company of New Hampshire (the registrant) on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission (the Report), we, Leon J. Olivier, Chief Executive Officer of the registrant, and David R. McHale, Senior Vice President and Chief Financial Officer of the registrant, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Leon J. Olivier
(Signature)
Leon J. Olivier
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

Date: February 28, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Western Massachusetts Electric Company (the registrant) on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission (the Report), we, Leon J. Olivier, Chief Executive Officer of the registrant, and David R. McHale, Senior Vice President and Chief Financial Officer of the registrant, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Leon J. Olivier
(Signature)
Leon J. Olivier
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

Date: February 28, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

February 28, 2008

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, DC 20459-1004

Ladies and Gentlemen:

Pursuant to the requirements of the Securities and Exchange Act of 1934 under Section 13 or 15(d) submitted herewith is the combined Annual Report on Form 10-K for the year ended December 31, 2007, for the companies noted below.

Northeast Utilities
The Connecticut Light and Power Company
Western Massachusetts Electric Company
Public Service Company of New Hampshire

The financial statements included in the aforementioned report on Form 10-K for the year ended December 31, 2007 reflect changes from the preceding year in accounting principles or practices related to the adoption of Financial Accounting Standards Board Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109." These changes are fully disclosed in the accompanying notes to the consolidated financial statements included in the aforementioned Form 10-K.

Very truly yours.

/s/ Timothy J. Griffin

Timothy J. Griffin
Assistant Controller - Corporate Accounting