CONNECTICUT LIGHT & POWER CO
Form 10-K
February 27, 2009

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, 2008

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	02-0181050

780 North Commercial Street
Manchester, New Hampshire 03101-1134
Telephone: (603) 669-4000

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.
Northeast Utilities	Common Share Purchase Rights	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 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
√	

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
	√

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
√	

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. [ ]

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	√		
The Connecticut Light and Power Company			√

Public Service Company of New Hampshire	√
Western Massachusetts Electric Company	√

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

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

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, 2008) was **$3,970,521,694** based on a closing sales price of **$25.53** per share for the 155,523,764 common shares outstanding on June 30, 2008. **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, 2009
Northeast Utilities Common shares, $5.00 par value	155,878,897 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 the Northeast Utilities Proxy Statement expected to be dated April 1, 2009	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
CRC	CL&P Receivables Corporation
HWP	Holyoke Water Power Company
Mt. Tom	Mt. Tom generating plant
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, Boulos, NGS, and SECI. For further information, see Note 17, "Segment Information," to the consolidated financial statements.
NUSCO	Northeast Utilities Service Company
NU parent and other companies	NU parent and other companies is comprised of NU parent, NUSCO, HWP (since January 1, 2007) and other subsidiaries, including The Rocky River Realty Company and The Quinnehtuk Company (both real estate subsidiaries), Mode 1 Communications, Inc. 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 and WMECO, the generation segment of PSNH, and Yankee Gas, a natural gas local distribution company. For further information, see Note 17, 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 2006 and the remainder of which was wound down in the second quarter of 2007.

WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS

CDEP	Connecticut Department of Environmental Protection
DOE	United States Department of Energy
DPU	Massachusetts Department of Public Utilities
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
COLA	Cost of Living Adjustment
Con Edison	Consolidated Edison, Inc.
CTA	Competitive Transition Assessment
CYAPC	Connecticut Yankee Atomic Power Company
EDIT	Excess Deferred Income Taxes
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation No.
FMCC	Federally Mandated Congestion Charges
Globix	Globix Corporation
GSC	Generation Service Charge
GWH	Gigawatt Hours
ISO-NE	New England Independent System Operator or ISO New England, Inc.
KWH or kWh	Kilowatt-hours
KV	Kilovolt
LBCB	Lehman Brothers Commercial Bank, Inc.
LNG	Liquefied Natural Gas
LNS	Local Network Service
LOC	Letter of Credit
MGP	Manufactured Gas Plant
Millstone	Millstone Nuclear Generating station, made up Millstone 1, Millstone 2, and Millstone 3. All three units were sold in March 2001
Money Pool or Pool	Northeast Utilities Money Pool
MW	Megawatts
MYAPC	Maine Yankee Atomic Power Company
NYMPA	New York Municipal Power Agency
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pensions
PCRBs	Pollution Control Revenue Bonds
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
RRB	Rate Reduction Bonds or Rate Reduction Certificates issued by the Regulated Companies
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
VAR	Voltage Ampere Reactive
VIE	Variable Interest Entity
YAEC	Yankee Atomic Electric Company
Yankee Companies	CYAPC, MYAPC and YAEC

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

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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 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 our "forward-looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements 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 materially 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 or inaction by local, state and federal regulatory bodies, changes in business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products and services, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels and timing of capital expenditures, disruptions in the capital markets or other events that make our access to necessary capital more difficult or costly, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports 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 combined Annual Report on Form 10-K. 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 "Combined 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:

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The Connecticut Light and Power Company (CL&P), a regulated electric utility which serves residential, commercial and industrial customers in parts of Connecticut.

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Public Service Company of New Hampshire (PSNH), a regulated electric utility which serves residential, commercial and industrial customers in parts of New Hampshire.

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Western Massachusetts Electric Company (WMECO), a regulated electric utility which serves residential, commercial and industrial customers in parts of western Massachusetts; and

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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, 2008, NU Enterprises's remaining business consisted of (i) Select Energy Inc. s 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 99.5 percent of our total earnings for 2008, excluding an after-tax charge of $29.8 million resulting from the settlement of litigation with Consolidated Edison, Inc. (Con Edison), with electric distribution (including PSNH s generation activities) representing approximately 42.6 percent, electric transmission representing approximately 47.6 percent, and natural gas distribution representing approximately 9.3 percent. At December 31, 2008, 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 (Boulos), (iv) the remaining business of Select Energy Contracting, Inc. (SECI), (iv) NGS Mechanical, Inc., and (v) NU Enterprises parent.

For information regarding each of NU s segments, see Note 17, "Segment Information," to the Consolidated Financial Statements in this Annual Report on Form 10-K.

REGULATED ELECTRIC DISTRIBUTION

General

NU s distribution segment is made up of the distribution businesses of CL&P, PSNH and WMECO, which are primarily engaged in the distribution of electricity in Connecticut, New Hampshire and western Massachusetts, respectively, plus PSNH s regulated electric generation business. The following table shows the sources of 2008 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	**Total Operating Companies**
Residential	55%

Commercial	35%
Industrial	9%
Other	1%
Total	100%

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A summary of changes in the operating companies   electric kilowatt-hour (kWh) distribution sales for the 12-months ended December 31, 2008 as compared to December 31, 2007 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Electric							
	CL&P		PSNH		WMECO		Total	
	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Decrease	We Norr Perc Dec
Residential	(4.1)%	(2.7)%	(2.2)%	(1.0)%	(3.1)%	(2.1)%	(3.6)%	
Commercial	(1.3)%	(0.7)%	(1.2)%	(0.4)%	(2.6)%	(2.1)%	(1.4)%	
Industrial	(9.8)%	(9.3)%	(6.1)%	(5.4)%	(8.7)%	(8.5)%	(8.6)%	
Other	(3.2)%	(3.2)%	2.2 %	2.2 %	(14.6)%	(14.6)%	(3.7)%	
Total	(3.7)%	(2.8)%	(2.5)%	(1.6)%	(4.2)%	(3.5)%	(3.5)%	

Retail electric sales in 2008 were lower than those in 2007. The 2008 weather normalized decrease of 2.6 percent reflects the fact that our customers are responding to the volatile costs of energy and to the economic conditions of our region and the nation. We believe customers will continue to respond to these factors and to the recent and ongoing developments in the financial markets resulting in an estimated decline in weather-normalized sales of approximately 1 percent in 2009.

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

Comparable to our sales results in 2008, our uncollectibles expense has also been influenced by the adverse economic conditions of our region. Our write-offs as a percentage of revenues increased in 2008 for all our electric distribution companies. Similar to changes in our retail sales, changes in our uncollectibles expense have less of an impact on earnings of our electric distribution companies than in prior years as a portion of the uncollectibles expense for each of the electric distribution companies is allocated to its respective energy supply rate and recovered as a tracked expense.

THE CONNECTICUT LIGHT AND POWER COMPANY - DISTRIBUTION

CL&P s distribution segment is primarily engaged in the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2008, 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 2008 electric franchise retail revenues for CL&P based on categories of customers:

CL&P	
Residential	59%
Commercial	34%
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.

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. CL&P also has 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 or bonds (RRBs) 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 stranded costs being recovered through securitization, CL&P s stranded costs included, as of December 31, 2008, 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 electric distribution company. Under "Standard Service" rates for customers with less than 500 kW of demand and "Supplier of Last Resort Service" rates for customers with 500 kW of demand or greater, CL&P purchases power for those customers who do not choose a competitive energy supplier and passes through the cost to ratepayers through the "Generation Service Charge" and the "Bypassable Federally Mandated Congestion Charge" (FMCC) components of the customer s bill, which are 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 rates or Supplier of Last Resort Service rates. However, CL&P has experienced some customer migration to competitive energy suppliers, with the movement concentrated among larger customers. Because this customer migration is only for energy supply service, there is no impact on the delivery portion of the business or the operating income of CL&P.

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).

On January 28, 2008, the DPUC approved $77.8 million, or 11.7 percent, and $20.1 million, or 2.6 percent, in annual increases in CL&P s distribution rates, effective February 1, 2008 and February 1, 2009, respectively. The rate decision included an ROE of 9.4 percent, with CL&P continuing its earnings sharing mechanism, which provides that ratepayers and shareholders share equally in any earnings in excess of its allowed regulatory ROE. 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," in this Annual Report on Form 10-K.

Regulatory Update

On May 2, 2008, the DPUC approved CL&P s revised metering compliance plan that would meet the DPUC's objective of making time-of-use rates available to CL&P customers. The DPUC decision authorized a pilot program involving the installation of advanced metering infrastructure (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 expects to conduct the AMI pilot with approximately 3,000 customers during the summer of 2009. The estimated incremental cost of the program is expected to be between $10.6 million to $13 million and such costs are authorized to be recovered from customers, initially through CL&P s FMCC charges. The non-incremental operating and maintenance expenses are projected to be less than $2 million.

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

Also in 2008, CL&P and UI entered into contracts for differences (Peaker CfDs) with developers of three proposed peaking generation units totaling 506 MW of summer peaking capacity, as approved by the DPUC. The Peaker CfDs provide for the payment to the developer of the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. As directed by the DPUC, CL&P and UI will share the net costs and benefits of the Peaker CfDs on a basis of 80 percent and 20 percent, respectively. CL&P s portion of the costs and benefits will be paid by or refunded to its customers

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

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

For further information on regulatory actions affecting CL&P, see "Regulatory Developments and Rate Matters - Connecticut - CL&P" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

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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 Service 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 price 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 for Standard Service and to date one tranche has been filled for 2011.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE - DISTRIBUTION

PSNH s distribution segment (which includes its regulated generation) is primarily engaged in the generation, purchase, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2008, PSNH furnished retail franchise electric service to approximately 493,000 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 (Northern Woods Power Project) at its Schiller Station in Portsmouth, New Hampshire, which was converted from a coal-burning unit in December 2006.

The following table shows the sources of 2008 electric franchise retail revenues based on categories of customers:

PSNH	
Residential	44%
Commercial	40%
Industrial	16%
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.

PSNH s Energy Service (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 annually with the NHPUC, with a six-month true-up, 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 July 1, 2008, PSNH s Delivery Service (DS) rates decreased by $0.4 million annually. This amount consisted of a $3.4 million rate reduction related to the full recovery of a rate differential recoupment and an increase of approximately $3 million per year for a two-year period effective July 1, 2008 to eliminate a negative balance in the major storm cost reserve and restore the intended reserve level of $1 million.

Pursuant to a distribution and transmission rate case settlement agreement between PSNH, the NHPUC staff and the Office of Consumer Advocate, the NHPUC approved PSNH s petition seeking to establish a Transmission Cost Adjusting Mechanism (TCAM) rate to be reset annually consistent with the rate settlement agreement. On May 13, 2008, PSNH filed a July 1, 2007 through June 30, 2008 TCAM reconciliation and a projected TCAM rate to be billed effective July 1, 2008 related to July 1, 2008 through June 30, 2009 TCAM costs.

Under New Hampshire law, the Stranded Cost Recovery Charge (SCRC) allows PSNH to recover its stranded costs, including expenses incurred through mandated power contracts and other long-term investments and obligations. PSNH has financed a significant portion of its stranded costs through securitization by issuing RRBs 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 makes an SCRC reconciliation filing with the NHPUC 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 this Annual Report on Form 10-K.

Under the terms of the order issued by the NHPUC approving PSNH s 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 2008 due to its performance and favorable pricing in the Massachusetts and Rhode Island markets for the RECs. As a result, customers and shareholders will share equally a benefit of about $7.8 million of incremental revenues for 2008.

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

On December 11, 2008, a major ice storm struck portions of New England, severely damaging PSNH s distribution systems. This was the most severe ice storm in PSNH s history. Of the 440,000 New Hampshire homes and businesses that lost power, 322,000 were served by PSNH. Restoration operations commenced on December 11, 2008 and were substantially completed by December 25, 2008. PSNH utilized its own line crews, local contractors, line crews from other NU subsidiaries and numerous other line crews from the eastern United States and Canada.

The operating cost of storm restorations that meet a NHPUC specified criteria are funded through the Major Storm Costs Reserve (MSCR). Capital costs for any storm work are charged to property, plant and equipment and are recovered through the normal distribution ratemaking process. As the December 2008 ice storm met the MSCR criteria, \$62.7 million of total estimated repair costs of \$75 million associated with this storm were charged to the MSCR at December 31, 2008. PSNH intends to request recovery of these costs as part of its next delivery rate proceeding with the NHPUC. Out of the remaining total storm costs incurred through December 31, 2008, \$6.5 million has been expensed and \$5.6 million has been capitalized to plant and equipment. PSNH expects to recognize an additional \$10 million in 2009 when the weather is warmer and additional clean-up and repairs can be performed. We carry \$15 million of storm-related insurance system-wide and to the extent that any insurance proceeds are received, a portion would be allocated to PSNH to reduce the amount of deferred or expensed storm costs.

Regulatory Update

In 2006, New Hampshire enacted a law requiring PSNH to reduce the mercury emissions for its coal fired plants by at least 80 percent (with co-benefits of reduction in sulfur dioxide (SO2) emissions as well). Wet scrubber technology will be installed at Merrimack Station in Bow New Hampshire no later than July 1, 2013. Following an August 2008 announcement by PSNH that the cost of this installation would be increasing from the original estimate of \$250 million to \$457 million, the NHPUC opened an inquiry to determine whether it had authority to assess whether the project is in the public interest. In September 2008, the NHPUC ruled that its authority is limited to determining at a later time the prudence of the costs incurred in complying with the legislation. In October 2008, several parties filed motions with the NHPUC requesting a reconsideration of its ruling; these motions were rejected. On December 11, 2008, several parties involved in the filing of the October 2008 motion for a rehearing filed an appeal with the New Hampshire Supreme Court requesting that the Court overturn the NHPUC finding that it lacked present authority over this matter. The Supreme Court has indicated that it will hear this appeal, but has not yet issued a schedule for oral arguments.

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

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

Sources and Availability of Electric Power Supply

During 2008, about 67 percent of PSNH s load was met through its own generation and long-term power supply rate orders and contracts with third parties. The remaining 33 percent 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 2009 in a similar manner.

New Hampshire s "Renewable Energy Act" establishes renewable portfolio standards for electricity sold in the state that require annual increases in the percentage of the electricity sold to retail customers having direct ties to renewable sources. The renewable sourcing requirements began in 2008 and increase each year to reach 23.8 percent by 2025. PSNH plans to meet these standards, in part, through the purchase of Renewable Energy Certificates (RECs) from qualified renewable energy resources. For each MWH of energy produced from a qualifying resource, the producer will receive one REC. Energy suppliers, like PSNH, will purchase these RECs from the producers and will use them to satisfy the RPS requirements. To the extent that PSNH is unable to purchase sufficient RECs, it will be required to make up the difference between the RECs purchased and its total obligation by making an alternative compliance payment (ACP) for each REC requirement for which PSNH is deficient. The costs of both the RECs and ACPs do not impact earnings, as these costs are being recovered by PSNH through its ES rates. For further information, see "Regulatory Developments and Rate Matters - New Hampshire" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

WESTERN MASSACHUSETTS ELECTRIC COMPANY - DISTRIBUTION

WMECO s distribution segment is engaged in the purchase, delivery and sale of electricity to residential, commercial and industrial customers. At December 31, 2008, 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. On December 31, 2008, WMECO purchased all of the transmission-related assets of its affiliates, Holyoke Water Power Company (HWP) and Holyoke Power and Electric Company (HP&E) for approximately $4 million.

The following table shows the sources of 2008 electric franchise retail revenues based on categories of customers:

WMECO	
Residential	58%
Commercial	32%
Industrial	9%
Other	1%
Total	100%

Rates

WMECO is subject to regulation by the Massachusetts Department of Public Utilities (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.

WMECO collects its transmission costs through a transmission adjustment clause, which is adjusted annually, thereby allowing WMECO to recover all of its retail transmission expenses on a timely basis.

WMECO also has 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 RRBs secured by the right to recover stranded costs from customers over time. It is recovering the costs of securitization through rates.

On January 1, 2008, WMECO s distribution rates increased by $3 million annually as approved by the Massachusetts DPU in December 2006. WMECO adjusted its rates to include the distribution increase, new basic service contracts, and changes in several tracking mechanisms. On December 29 and 30, 2008, the DPU approved WMECO s proposed rate changes effective January 1, 2009. The rate changes were made in accordance with WMECO s various tracking mechanisms.

The major ice storm on December 11, 2008 also impacted parts of Massachusetts, including areas served by WMECO. As this storm met the storm costs reserve criteria approved in WMECO s last distribution rate case settlement, $11.3 million of the total $13.8 million estimated repair costs associated with this storm were recognized as a deferred asset at December 31, 2008. WMECO expects to begin recovery of these costs in its next distribution rate proceeding. The DPU has opened a formal docket to review storm restoration efforts by the state's utilities.

For further information on WMECO s rates, see "Regulatory Developments and Rate Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

Regulatory Update

On July 16, 2008, the DPU issued a decision in its decoupling generic docket requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. The decision rejected calls for partial decoupling or decoupling by rate design in favor of full decoupling by rate class. On September 2, 2008, WMECO notified the DPU that it expects to file its next distribution rate case in mid-2010 to be effective January 1, 2011. That case will include a proposal to fully decouple distribution revenues from kilowatt-hour sales.

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

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

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Removes the cap on utility expenditures for EE and demand response (DR).

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Requires utilities to file three-year EE and DR plans with a newly created Energy Efficiency Council;

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Requires utilities to sign long-term contracts for renewable resources;

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Allows each utility to own and operate up to 50 MW of solar generation;

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Requires utilities to file a plan with the DPU for a smart grid pilot; and

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Increases penalties for failure to meet service quality standards from 2 percent of transmission and distribution revenues to 2.5 percent.

By April 30, 2009, WMECO is required to prepare a three-year EE and DR investment plan related to the cost of EE and DR programs established by the Act for review by the Energy Efficiency Council and, ultimately, the DPU. In addition, WMECO filed a program with the DPU on February 11, 2009 providing for a three-phase solar generation program subject to DPU authorization prior to each phase. The initial phase calls for 6 MW of solar generation to be installed at eight host sites in WMECO's service territory upon receipt of DPU approval. This phase of the project is expected to be completed as early as 2010 at a cost of approximately $42 million. The second phase includes an additional 9 MW extending through 2012, and the third and final phase could increase total capacity to the 50 MW maximum. The DPU has six months to issue a decision on WMECO's plan. WMECO is otherwise precluded from making new generation investments, but has not yet included any solar generation investment opportunities in its capital expenditure plans.

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. On May 14, 2008, WMECO entered into an agreement to secure 50 percent of residential, small commercial and industrial, and street lighting loads for the July 1, 2008 through June 30, 2009 period, and on November 3, 2008 WMECO entered into an agreement to secure power for half of its residential, small commercial and industrial, and street lighting loads for the January 1 through December 31, 2009 period. WMECO will issue an RFP in the second quarter of 2009 to secure the remaining 50 percent of its residential, small commercial and industrial, and street lighting loads for the July 1 through December 31, 2009 period and 50 percent of the load for January 1, 2010 through June 30, 2010. For its large commercial and industrial customers, WMECO entered into an agreement on November 3, 2008 to secure power for the first quarter of 2009 and an agreement to secure power for the second quarter 2009 on February 10, 2009. RFPs will be issued quarterly to secure power for the balance of the year.

REGULATED GAS DISTRIBUTION

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) in 2008 was 49.8 billion cubic feet (Bcf) compared with 49.7 Bcf in 2007. 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. The LNG facility is capable of storing the equivalent of 1.2 Bcf of natural gas.

Yankee Gas earned $27.1 million on total gas operating revenues of approximately $577.4 million for 2008. The following table shows the sources of 2008 total gas operating revenues:

Yankee Gas	
Residential	45%
Commercial	29%
Industrial	23%

Other	3%
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 17, "Segment Information," contained within this Annual Report on Form 10-K.

A summary of changes in Yankee Gas firm natural gas sales for 2008 as compared to 2007 on an actual and weather normalized basis (using a 30-year average) is as follows:

Yankee Gas		
	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase
Residential	(2.0)%	(0.1)%
Commercial	(0.2)%	1.4%
Industrial	9.2%	9.6%
Total	2.1%	3.4%

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

Although Yankee Gas is not subject to the FERC's jurisdiction, the FERC has limited oversight with respect to certain reporting and 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.

Yankee Gas recovers its cost of gas supplied to customers through a Purchased Gas Adjustment (PGA) 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. On June 11, 2008, the DPUC issued a final order pursuant to which Yankee Gas was required to refund to customers approximately $5.8 million in recoveries under its Purchased Gas Adjustment clause. Yankee Gas results for 2008 reflect an after-tax charge of $3.5 million associated with that decision.

Under a settlement of its distribution rate filing with the Connecticut Office of Consumer Counsel and the DPUC s Prosecutorial Division, Yankee Gas s base rate increased, effective July 1, 2007, by $22 million, or 4.2 percent, net of expected pipeline and commodity cost savings resulting primarily from completion of Yankee Gas s LNG facility, and Yankee Gas was allowed an authorized ROE of 10.1 percent. Yankee Gas will return to ratepayers 100 percent of all earnings in excess of the allowed 10.1 percent ROE. As a result of the base rate increase, the amount of gas supply costs charged to customers through the PGA decreased.

FORWARD CAPACITY MARKETS

On December 1, 2006, a FERC-approved Forward Capacity Market (FCM) settlement agreement was implemented, and the payment of fixed compensation to generators began. The second forward capacity auction concluded on December 10, 2008 for the capacity year June 2011 through May 2012. The bidding reached the established minimum of $3.60 per kilowatt-month with 4,755 MW of excess remaining capacity. This means the effective price will be $3.12 per kilowatt-month compared to the equivalent first forward capacity auction price of $4.25 per kilowatt-month for the 12-month capacity period ending May 31, 2011 and $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.

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 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 works 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 costs of our major transmission facilities are regionalized throughout New England.

Wholesale Transmission Rates

Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under ISO-NE s 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 100 percent of the construction costs of the New England East-West Solutions (NEEWS) projects. Both the LNS and RNS rates 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 March 24, 2008, the FERC issued an order on rehearing confirming its initial order setting the base ROE on transmission projects for the New England transmission owners, including NU s subsidiaries. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC s earlier decision granting a 100 basis point adder for new transmission projects that are built as part of the ISO-NE Regional System Plan and are "completed and on line" by December 31, 2008. In order to receive incentives for projects completed after December 31, 2008, transmission owners are required to make project-specific incentive requests that meet the nexus requirements under FERC guidelines for new projects. In 2008, we recognized $6 million in transmission segment earnings related to this order. This order has been appealed to the D.C. Circuit Court of Appeals by various state regulators and consumer advocates. The court has set a schedule for the briefing to be concluded in the second quarter of 2009, with no date set for argument.

On May 16, 2008, CL&P filed an application with the FERC to receive ROE incentives for its portions of the Middletown-Norwalk project seeking a waiver of the "completed and on line" date of December 31, 2008 to earn the ROE incentives. Alternatively, CL&P asked FERC to find that this project met the nexus test requirements for incentives under FERC s guidelines for new projects, and also requested an additional 50 basis point adder for advanced technology used in the project. FERC subsequently granted the waiver request and approved the 100 basis point incentive for the entire Middletown-Norwalk project. The FERC also found that the project met the nexus test, and granted an additional 50 basis point adder for the advanced technology aspects of the 24-mile underground portion of the project. CL&P completed the project by the end of 2008. The 50 basis point adder results in a total ROE for the underground portion of the Middletown-Norwalk project of 13.1 percent, which represents the overall ROE limit established by FERC. Certain state regulators and municipal utilities had sought rehearing which was denied by FERC and Connecticut state regulators have since appealed the order to the D.C. Circuit Court of Appeals.

On November 17, 2008, the FERC issued an order granting certain incentives and rate amendments to National Grid USA (National Grid) and us, for certain components of the proposed NEEWS projects. The approved incentives included (1) an ROE of 12.89 percent, which includes an incentive of 125 basis points; (2) inclusion of 100 percent construction work in progress (CWIP) costs in rate base; and (3) full recovery of prudently incurred costs if any portion of NEEWS is abandoned for reasons beyond our or National Grid's control. Our portion of the components that received these incentives is estimated to cost approximately $1.41 billion of our $1.49 billion share of the total NEEWS projects. Several parties have sought rehearing of this FERC order on which FERC has not yet acted.

Transmission Projects

In December 2008, we completed the last of our four southwest Connecticut transmission upgrades. The first of those projects, a new 345KV/115KV overhead and underground line between Bethel, Connecticut and Norwalk, Connecticut, was placed in service in October 2006. The remaining three projects were placed in service in 2008. The Middletown-Norwalk project, a 69-mile, 345KV/115 KV transmission project from Middletown to Norwalk, Connecticut constructed jointly with UI, was completed in December 2008. CL&P's portion of this project cost approximately $950 million, $100 million lower than our earlier cost estimate. The 45-mile overhead section of the project entered service on August 28, 2008 and the 24-mile underground section entered service on December 16, 2008. The Glenbrook Cables project, a two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut entered service on November 11, 2008 at a project cost of approximately $239 million, $16 million higher than previous estimates due to increased construction costs to remove underground obstacles. The Long Island Replacement Cable project, a 138KV, 11-mile undersea transmission project between Norwalk, Connecticut and Northport-Long Island, New York was completed in September 2008. CL&P owns 51 percent of the project, with Long Island Power Authority owning the remainder, and CL&P's portion of the project costs is anticipated to be approximately $78 million.

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

The first of the NEEWS projects, the Greater Springfield Reliability Project, which involves a 115 KV/345 KV line from Ludlow, Massachusetts to North Bloomfield, Connecticut, is the largest and most complicated project within NEEWS. This project is expected

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

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

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

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

On December 12, 2008, we submitted jointly with NSTAR, a petition with the FERC requesting a declaratory order that would allow us and NSTAR to enter into a bilateral transmission services agreement with H.Q. Energy Services (U.S.) Inc. (HQUS), a wholly-owned subsidiary of Hydro-Québec. Under such an agreement, NU and NSTAR subsidiaries would sell to HQUS 1,200 megawatts of firm electric transmission service over a new, participant-funded transmission tie line connecting New England with the Hydro-Québec system in order for HQUS to sell and deliver this same amount of firm electric power from Canadian low-carbon energy resources to New England.

If FERC issues the declaratory order as we anticipate, NU and NSTAR would subsequently seek approval from FERC of the specific terms and conditions of the transmission arrangement and approvals from state regulators of the terms and conditions of the power purchase arrangements. NU, NSTAR and HQUS have signed memoranda of understanding to develop this transmission project on an exclusive basis. This project would provide a competitive source of low-carbon power that is favorable in comparison to current alternatives. It also would provide for an expansion of New England s transmission system without raising regional transmission rates.

NU, NSTAR and HQUS have also begun discussions on the specifics of a potential long-term power purchase agreement that would ensure the line is utilized to bring low-carbon power to benefit New England customers. A FERC order is expected in the first half of 2009, and if the order approves the proposal, then NU and NSTAR plan to negotiate a power purchase agreement with HQUS later in 2009. The terms of such an agreement would be subject to regulatory approval in several states.

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

Transmission Rate Base

Under our FERC-approved tariff, transmission projects enter rate base once they are placed in commercial operation. Additionally, 100 percent of the NEEWS projects will enter rate base during their construction period. At the end of 2008, our transmission rate base was approximately $2.4 billion, including approximately $2.0 billion at CL&P, $250 million at PSNH and $80 million at WMECO. We forecast that our total transmission rate base will grow to approximately $5.0 billion by the end of 2013. 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	2009	2010	2011	2012	2013
CL&P	$2,024	$2,033	$2,224	$2,433	$2,454
PSNH	314	325	666	1,089	1,189
WMECO	125	218	488	729	876
Other	-	-	-	-	525
Totals	$2,463	$2,576	$3,378	$4,251	$5,044

The projected rate base amounts reflected above assume that $1.49 billion in transmission projects associated with NEEWS will be completed before the end of 2013 and the transmission line connecting to HQUS is built. Numerous factors, some of which are beyond our control, may impact the rate base amounts above, including the level and timing of capital expenditures and plant placed in service and regulatory approvals. 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 Discussion and Analysis of Financial Condition and Results of Operations" contained in this Annual Report on Form 10-K.

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 2008, including amounts incurred but not paid, cost of removal, allowance for funds used during construction and the capitalized portions of pension and PBOP expense or income (all of which are non-cash factors in determining rate base), totaled approximately $1.3 billion, almost all of which was expended by the regulated companies. The capital expenditures of these companies in 2009 are estimated to total approximately $851 million. Of this amount, approximately $375 million is expected to be expended by CL&P, $310 million by PSNH, $100 million by WMECO and $66 million by Yankee Gas. This capital 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 2009. We expect to evaluate needs beyond 2009 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.

CL&P s transmission capital expenditures in 2008 totaled approximately $586 million. The decrease in transmission segment capital expenditures in 2008 as compared with 2007 was primarily due to the early completion of the major southwest Connecticut transmission projects discussed above. For 2009, CL&P projects transmission capital expenditures of approximately $97 million. During the period 2009 through 2013, CL&P plans to invest approximately $974 million in transmission projects, the majority of which will be for NEEWS.

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 2008, CL&P's distribution capital expenditures totaled approximately $297 million. CL&P projects its distribution capital expenditures in 2009 to be approximately $278 million. CL&P plans to spend approximately $1.59 billion on distribution projects during the period 2009-2013. 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 $2.0 billion at the end of 2008 to approximately $2.5 billion by the end of 2013, and its rate base for distribution assets is projected to increase from approximately $2.0 billion to approximately $3.0 billion over the same period.

In 2008, PSNH's transmission capital expenditures totaled approximately $82 million, its distribution capital expenditures totaled $98 million and its generation capital expenditures totaled $74 million. For 2009, PSNH projects transmission capital expenditures of approximately $58 million, distribution capital expenditures of approximately $96 million and generation capital expenditures of approximately $156 million. The increase in generation capital expenditures is mostly due to the expenditures for the Merrimack Clean Air project. During the period 2009-2013, PSNH plans to spend approximately $1.1 billion on transmission projects, approximately $559 million on distribution projects, and $623 million on generation projects. 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 $250 million at the end of 2008 to approximately $1.2 billion by the end of 2013, and its rate base for distribution and generation assets is projected to increase from approximately $1.0 billion to approximately $2.0 billion over the same period.

In 2008, WMECO's transmission capital expenditures totaled approximately $44.2 million and its distribution capital expenditures totaled approximately $37.8 million. In 2009, WMECO projects transmission capital expenditures of approximately $70 million and distribution capital expenditures of approximately $30 million. During the period 2009-2013, WMECO plans to spend approximately $888 million on transmission projects, with the bulk of that amount to be spent on the NEEWS Greater Springfield Reliability Project, and approximately $168 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 to approximately $876 million by the end of 2013 and its rate base for distribution assets is projected to increase from approximately $374 million to approximately $497 million over the same period.

In 2008, Yankee Gas s capital expenditures totaled approximately $44 million. For 2009, Yankee Gas projects total capital expenditures of approximately $66 million. During the period 2009-2013, Yankee Gas plans on making approximately $399 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 $685 million at the end of 2008 to approximately $890 million by the end of 2013.

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 in this Annual Report on Form 10-K.

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, 2008, our competitive businesses consisted solely of (i) Select Energy s few remaining wholesale marketing contracts and NGS and its affiliates, which are winding down, and (ii) Boulos, NU Enterprises remaining active energy services business.

On May 31, 2008, Select Energy s remaining wholesale sales contract in the PJM power pool expired. Select Energy s wholesale contract with The New York Municipal Power Agency (NYMPA) and related supply contracts expire in 2013. In addition to the PJM and NYMPA contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to operate and purchase the output of a certain generating facility in New England through 2012.

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 15, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements, contained within this Annual Report on Form 10-K.

FINANCING

We paid dividends on our common shares totaling $129.1 million in 2008, compared to $121 million in 2007, reflecting increases in the quarterly dividend amount that were effective in the third quarters of 2007 and 2008. On February 10, 2009, the NU Board of Trustees declared a quarterly dividend of $0.2375 per share, payable on March 31, 2009, an increase of $0.10 per share above the previous annualized rate of $0.85 per share. This dividend reflects the company s policy, announced in November 2008, of targeting a dividend payout ratio of approximately 50 percent of earnings, with a goal of continuing the policy of increasing the dividend at a rate above industry average and providing an attractive return to shareholders. NU expects to revisit its dividend levels in the first quarter of each year.

In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In 2008, CL&P, PSNH, WMECO and Yankee Gas paid $106.5 million, $36.4 million, $39.7 million, and $31 million, respectively, in common dividends to NU parent. In 2008, NU parent contributed $210 million of equity to CL&P, $75.6 million to PSNH, $16.3 million to WMECO, and $20.8 million to Yankee Gas.

NU parent s ability to pay common dividends is subject to approval by the Board of Trustees and to NU s future earnings and cash flow requirements. It is not regulated under the Federal Power Act, but may be limited by certain state statutes, the leverage restrictions tied to its required ratio of consolidated total debt to total capitalization in its revolving credit agreement, and the ability of its subsidiaries to pay common dividends. The Federal Power Act does, however, limit the payment of dividends by CL&P, PSNH and WMECO to their respective retained earnings balances unless a higher amount is approved by FERC, and PSNH is required to reserve an additional amount under its FERC hydroelectric license conditions. In addition, certain state statutes may impose additional limitations on the regulated companies. CL&P, PSNH, WMECO and Yankee Gas also are parties to a revolving credit agreement that imposes leverage restrictions.

Our total debt, including short-term debt, capitalized lease obligations and prior spent nuclear fuel liabilities, but not including RRBs, was approximately $4.8 billion as of December 31, 2008.

During 2008, the NU companies issued an aggregate of $760 million of long-term debt, as follows: On May 27, 2008, CL&P issued $300 million of 10-year first and refunding mortgage bonds carrying a coupon rate of 5.65 percent, and PSNH issued $110 million of 10-year first mortgage bonds with a coupon rate of 6.00 percent. On June 5, 2008, NU parent issued $250 million of five-year senior unsecured notes with a coupon rate of 5.65 percent, and on October 7, 2008, Yankee Gas issued $100 million of 10-year first mortgage bonds at 6.9 percent. In addition, on February 13, 2009, CL&P issued $250 million of 10-year first mortgage bonds at 5.5 percent.

NU parent has a combined credit line and letter of credit (LOC) facility in a nominal aggregate amount of $500 million, including the lending commitment of Lehman Brothers Commercial Bank, Inc. (LBCB) (as discussed below), which expires on November 6, 2010. At December 31, 2008, NU parent had $304 million of borrowings and $87 million of LOCs issued for the benefit of certain subsidiaries outstanding under that facility. NU parent had approximately $50 million of borrowing availability on this facility as of February 25, 2009, excluding the remaining unfunded commitment of LBCB. NU also had approximately $466 million of externally invested cash at February 25, 2009.

The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million, including the lending commitment of LBCB, which also expires on November 6, 2010. There were $315 million of short-term borrowings outstanding under that facility at December 31, 2008. We had approximately $1 million of borrowing availability on this facility as of February 25, 2009, excluding the remaining unfunded commitment of LBCB. NU also had approximately $466 million of externally invested cash at February 25, 2009.

The lenders under these facilities are: Bank of America, N.A.; Barclays Bank PLC; BNY Mellon, N.A.; Citigroup Inc.; HSBC Bank USA, N.A.; JPMorgan Chase Bank, N.A.; LBCB; Sumitomo Mitsui Banking Corporation (Sumitomo); Toronto Dominion (Texas) LLC; Union Bank of California, N.A.; Wachovia Bank, N.A.; and Wells Fargo Bank, N.A. Lehman Brothers Holdings Inc., the parent of LBCB, filed for Chapter 11 bankruptcy protection in September 2008. LBCB's original aggregate lending commitment under the two facilities was $85 million, of which $30 million was assigned to Sumitomo in late September 2008. At December 31, 2008, LBCB had advanced approximately $19.2 million under the facilities and had declined to fund the remainder of its commitment. As a result, when current loans from LBCB are repaid, we will be limited to an aggregate of $845 million of borrowing capacity under our credit facilities, which we believe will provide sufficient operating flexibility to maintain adequate amounts of liquidity.

PSNH has outstanding approximately $407 million of PCRBs, one series of which, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this series of PCRBs has been held by remarketing agents as the result of failed auctions due to general market concerns. The interest rate on these PCRBs has reset by formula under the applicable documents every 35 days and has been between 0.2 percent and 4 percent since March 2008. The formula is based on a combination of the ratings on the PCRBs and an index rate, which provides for a current interest rate of 0.3 percent. We are not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agents.

In addition, CL&P has approximately $423.9 million of PCRBs, one series of which, in the aggregate principal amount of $62 million, had a fixed interest rate for a five-year period that expired on September 30, 2008. CL&P chose to acquire these PCRBs on October 1, 2008 as a result of poor liquidity in the tax-exempt market. These PCRBs, which mature in 2031, have not been retired, and CL&P expects to remarket them when conditions in the market improve.

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 percent. At December 31, 2008, 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 "Note 2, "Short-Term Debt," and Note 11, "Long-Term Debt," to the Consolidated Financial Statements and "Liquidity" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report on Form 10-K.

NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and other New England electric utilities are the stockholders of three inactive regional nuclear companies, Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company (MYAPC) and Yankee Atomic Electric Company (YAEC) (the Yankee Companies). 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 rates. The ownership percentages of CL&P, PSNH and WMECO in the Yankee Companies are set forth below:

	CL&P	PSNH	WMECO	Total
Connecticut Yankee Atomic Power Company	34.5%	5.0%	9.5%	49.0%
Maine Yankee Atomic Power Company	12.0%	5.0%	3.0%	20.0%
Yankee Atomic Electric Company	24.5%	7.0%	7.0%	38.5%

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," in this Annual Report on Form 10-K.

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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. PSNH owns generation assets and plans to spend approximately $457 million to install a wet flue gas desulphurization system at Merrimack Station to reduce mercury emissions of its coal fired plants in compliance with current New Hampshire law. Compliance with additional increasingly stringent environmental laws and regulations, particularly air and water pollution control requirements, may limit operations or require further 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.

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 SO2 and nitrogen oxides (NOX) 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 capped NOX, SO2 and carbon dioxide (CO2) emissions for current compliance beginning in 2007. In addition, a 2006 New Hampshire law requires PSNH to install a wet flue gas desulphurization system, known as "scrubber" technology, to reduce mercury emissions of its coal fired plants by at least 80 percent (with the co-benefit of reductions in SO2 emissions as well). Wet scrubber technology will be installed at Merrimack Station in Bow, New Hampshire. PSNH currently anticipates that compliance with this law will cost approximately $457 million. PSNH began site work for this project in November 2008. The project is scheduled to be completed by the end of 2012.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the Regional Greenhouse Gas Initiative (RGGI). RGGI is a cooperative effort by ten northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO2 emissions from fossil fuel-fired electric generating plants. It is the first market-based, mandatory cap-and-trade program in the U.S. designed to reduce greenhouse gas emissions. Each of the participating states has regulations in place to cap and then reduce the amount of CO2 that power plants in their region are allowed to emit. Power sector CO2 emissions are capped at current levels through 2014. The cap will then be reduced by 2.5 percent in each of the four years 2015 through 2018, for a total reduction of 10 percent. RGGI is composed of individual CO2 budget trading programs in each of the participating states. Each participating state s CO2 budget trading program establishes its respective share of the regional cap, and each state will issue CO2 allowances in a number equivalent to its portion of the regional cap. Each CO2 allowance represents a permit to emit one ton of CO2 in a specific year. The RGGI states will distribute CO2 allowances primarily through regional auctions.

Because CO2 allowances issued by any participating state will be usable across all state programs, the ten individual state CO2 budget trading programs, in the aggregate, will form one regional compliance market for CO2 emissions. Initial CO2 allowance auctions were held in 2008 as pre-compliance events to facilitate market price discovery and compliance planning by regulated CO2 emitters. A regulated power plant must hold CO2 allowances equal to its emissions to demonstrate compliance at the end of a three-year compliance period beginning in 2009.

Connecticut adopted regulations in connection with RGGI in July 2008 which established an auction clearing price threshold of $5 per CO2 allowance, above which all auction proceeds will be rebated to customers. For proceeds up to the clearing price threshold, 69.5 percent will be directed to the conservation and load management programs managed by the state s utilities in conjunction with the Energy Conservation Management Board. Seventy-five percent of the RGGI auction proceeds directed to conservation and load management programs will be allocated to CL&P s programs. Because CL&P does not own any generating assets, it is not required to acquire CO2 allowances; however, the costs will likely be included in wholesale rates charged to CL&P in standard offer type contracts.

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

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

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

The first regional auction of RGGI CO2 allowances took place on September 25, 2008. Six states offered allowances for sale. At the auction, more than 12.5 million CO2 allowances were sold at the clearing price of $3.07 per CO2 allowance. The auction raised $38.6 million for use by the six RGGI states. The next regional auction took place on December 17, 2008. All ten RGGI states participated and more than 31.5 million CO2 allowances were sold at a clearing price of $3.38 per allowance. The auction raised $106.5 million for use by the ten RGGI states. For 2009, four quarterly regional auctions are scheduled for March, June, September and December.

Each of the states in which we do business also has renewable portfolio standards (RPS). New Hampshire s renewable portfolio standards provision requires increasing percentages of the electricity sold to retail customers in the state, beginning in 2008, to have direct ties to renewable sources, ultimately reaching 23.8 percent by 2025. PSNH is 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. Connecticut's RPS statutes require that a specific percentage of the generation provided to Connecticut consumers be produced from renewable energy sources such as solar, hydropower, landfill gas, fuel cells and other similar sources. Beginning with a 4 percent requirement in 2004, the requirement increases each year. For 2009, the requirement is 12 percent, increasing to 14 percent by 2010, 19.5 percent by 2015 and 27 percent by 2020. Massachusetts RPS program required electricity suppliers to meet a 1 percent renewable energy standard in 2003, which increased to 4 percent for 2009 and has a goal of 15 percent by 2015.

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 agencies and private parties can attempt to impose liability on us for such past disposal. At December 31, 2008, 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 $27.4 million, representing 54 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 $27.4 million, a reserve of approximately $25.4 million has been established to address future investigation and/or remediation costs at MGP sites. In addition, Holyoke Water Power Company (HWP), a wholly-owned subsidiary of NU, is continuing to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a MGP, which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP and HG&E share responsibility for the site. HWP has already conducted substantial investigative and remediation activities.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP s 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. HWP has developed and begun to implement plans for

additional investigations in conformity with MA DEP s guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

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

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

For further information on environmental liabilities, see Note 7B, "Commitments and Contingencies - Environmental Matters" to the Consolidated Financial Statements contained in this Annual Report on Form 10-K.

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 undergoing relicensing proceedings. On January 16, 2009, FERC issued a new license for this project. The new license takes effect upon the July 3, 2009 expiration of its current license. The water quality certification associated with this new license has been appealed to the Vermont Environmental Court.

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, 2008, we employed a total of 6,189 employees, excluding temporary employees, of which 1,944 were employed by CL&P, 1,268 by PSNH, 366 by WMECO, 417 by Yankee Gas and 2,182 were employed by Northeast Utilities Service Company (NUSCO). Approximately 2,300 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 IDEA 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.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition. The extreme disruption in the capital markets has limited companies ability to access the capital and credit markets to support their operations and refinance debt and has led to higher financing costs compared to recent years. We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not satisfied by our operating cash flow, including construction costs. The cost of debt financing and the proceeds of equity financing may be materially adversely impacted by these market conditions. The inability to raise capital on favorable terms could negatively affect our ability to maintain and to expand our businesses. Our current credit ratings cause us to believe that we will continue to have access to the capital markets. However, events beyond our control, such as the disruption in global capital and credit markets in 2008, may create uncertainty that could increase our cost of capital or impair our ability to access the capital markets. In addition, certain of NU parent s subsidiaries rely, in part, on NU parent for access to capital. Circumstances that limit NU parent s access to capital could impair its ability to provide those companies with needed capital. The credit crisis could also have an impact on our lenders or our customers, causing them to fail to meet their obligations to us. Additionally, the crisis could have a broader impact on business in general in ways that could lead to reduced electricity and gas usage, which could have a negative impact on our revenues.

In addition, the consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth. Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers ability to pay bills in a timely manner and increase customer bankruptcies, which may lead to increased bad debt expenses.

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. 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 limited 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, the continued economic slowdown 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, as well as by a general economic slowdown. The impact of these increases has led to increased electricity and natural gas prices for our customers, which, coupled with the continued economic slowdown, 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 $3.5 billion in regulated electric transmission infrastructure from 2009 through 2013.

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 by the Transmission Operating 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 after February 1, 2010. In addition, after that date, other parties, such as state regulators, may seek certain changes to the regional cost allocation, which 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.

Judicial or regulatory proceedings or changes in regulatory or legislative policy could jeopardize completion of, or full recovery of costs incurred by PSNH in constructing, the Clean Air Project.

Pursuant to New Hampshire law, PSNH has begun work on the Clean Air Project at its Merrimack Station in Bow, New Hampshire. As a result of an increase in the estimated cost of the project from $250 million to $457 million, several parties have initiated legal proceedings challenging the project. These proceedings, or new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could result in the delay or cancelation of this project or add to its cost. Any delay or cancelation of the project would adversely affect our ability to achieve forecast levels of earnings. If the project were to be canceled, contract payments and termination costs would be a substantial portion of the contractual commitments entered into by PSNH. As of March 31, 2009, the contractual commitments are expected to total approximately $250 million. The actual amount of contract termination costs would depend on timing of the cancelation and negotiations with the contractors. At this time, we cannot predict any legislative or regulatory changes or the outcome of the pending legal proceedings.

In addition, PSNH s investment in the project after it is completed is subject to prudence review by the NHPUC at the time the project is placed in service. A prudence disallowance of a material nature could adversely affect PSNH s cash flows and results of operations. While we believe that all expenditures to date have been prudently incurred, we cannot predict the outcome of any prudency reviews should they occur. Our projected earnings and growth could be adversely affected were the NHPUC to deny recovery of some or all of PSNH s investment in the project.

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.

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, such as the ice storm that impacted New Hampshire in December 2008, 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, 2008, collateral in the form of cash or letters of credit in the amount of $23.2 million to unaffiliated counterparties and cash or letters of credit in the amount of $10 million to two independent system operators. While our credit facilities are sufficient in amounts that would be adequate to meet collateral calls at that level, our ability to meet any future collateral calls would depend on our liquidity and access to bank lines and the capital markets at such time.

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 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 excess electricity at low prices could negatively impact Select Energy's cost to serve the contracts.

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. 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" in this Annual Report on Form 10-K.

We are subject to legal proceedings which could result in large cash obligations.

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

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

Item 1B.

Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2.

Properties

Transmission and Distribution System

At December 31, 2008, our electric operating subsidiaries owned 29 transmission and 443 distribution substations that had an aggregate transformer capacity of 4,312,000 kilovolt amperes (kVa) and 29,401,000 kVa, respectively; 3,096 circuit miles of overhead transmission lines ranging from 69 KV to 345 KV, and 432 cable miles of underground transmission lines ranging from 69 KV to 345

KV; 34,897 pole miles of overhead and 2,925 conduit bank miles of underground distribution lines; and 536,203 underground and overhead line transformers in service with an aggregate capacity of 36,730,940 kVa.

Electric Generating Plants

As of December 31, 2008, 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	997,532
Total - Hydro-Conventional	(20 units)	1917-83	70,329
Total - Internal Combustion	(5 units)	1968-70	102,961
Total PSNH Generating Plant	(32 units)		1,170,822

*Claimed capability represents winter ratings as of December 31, 2008. The nameplate capacity of the generating plants is approximately 1,200 MW.

Neither CL&P nor WMECO owned any electric generating plants during 2008.

Yankee Gas

At December 31, 2008, 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. On December 31, 2008, WMECO purchased all of the transmission-related assets of its affiliates, HWP and HP&E, for approximately $4 million.

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 DPU subsequently determined that there were advantages to the exclusivity of service territories and issued a report to the Massachusetts Legislature recommending against, in this 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.

Prior to December 31, 2008, the two companies had locations in the public highways for their transmission lines. Such locations were 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. On December 31, 2008, HWP and HP&E sold all of their transmission-related assets to WMECO.

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.

Yankee Companies v. U.S. Department of Energy

Yankee Atomic Electric Company (YAEC), Maine Yankee Atomic Power Company (MYAPC), and Connecticut Yankee Atomic Power Company (CYAPC) (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 in 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. 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 Court of Appeals disagreed with the trial court s method of calculation of the amount of the DOE s liability, among other things, and vacated the decision of the Court of Federal Claims and remanded the case to make new findings consistent with its decision. 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.

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 and 2002.

2.

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. The trial has been scheduled for April 2009.

3.

Other Legal Proceedings

For further discussion of legal proceedings see the following sections of Item 1, "Business": "Regulated Electric Distribution," "Regulated Gas Operations," and "Regulated Electric Transmission" for information about various state regulatory 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.

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 NU or CL&P.

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

EXECUTIVE OFFICERS OF THE REGISTRANT

This information is provided by NU in reliance on General Instruction G of Form 10-K. All of the Company s officers serve terms of one year and until their successors are elected and qualified:

Name	Age	Title
Gregory B. Butler	51	Senior Vice President and General Counsel.
Peter J. Clarke	47	President and Chief Operating Officer and a Director of WMECO. Previously Vice President - Shared Services of Northeast Utilities Service Company (NUSCO), a subsidiary of NU.
Jean M. LaVecchia	57	Vice President - Human Resources of NUSCO.
David R. McHale	48	Executive Vice President and Chief Financial Officer.
Leon J. Olivier	60	Executive Vice President and Chief Operating Officer.
Shirley M. Payne*	57	Vice President - Accounting and Controller.
James B. Robb	48	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	63	Chairman of the Board, President and Chief Executive Officer.

*

On February 17, 2009, Ms. Payne resigned her position and was appointed Vice President - Shared Services of NUSCO, in each case, effective April 1, 2009.

Gregory B. Butler. Mr. Butler became Senior Vice President and General Counsel of NU effective December 1, 2005, and of CL&P, PSNH and WMECO, subsidiaries of NU, effective March 9, 2006, and was elected a Director of Northeast Utilities Foundation, Inc. effective December 1, 2002. Previously Mr. Butler served as 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. Mr. Clarke was elected President and Chief Operating Officer and a Director of WMECO, and a Director of Northeast Utilities Foundation, Inc., effective January 1, 2009. Previously, Mr. Clarke served as Vice President - Shared Services of NUSCO, CL&P, PSNH and WMECO, from January 1, 2008 to December 31, 2008; Vice President - Customer Operations of CL&P 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.

Jean M. LaVecchia. Ms. LaVecchia was elected Vice President - Human Resources of NUSCO, effective January 1, 2005 and was elected a Director of Northeast Utilities Foundation, Inc. effective January 30, 2007. Previously, Ms. LaVecchia served as Vice President - Human Resources and Environmental Services from May 1, 2001 to December 31, 2004.

David R. McHale. Mr. McHale was elected Executive Vice President and Chief Financial Officer of NU, CL&P, WMECO and PSNH, effective January 1, 2009, elected a Director of PSNH and WMECO, effective January 1, 2005, of CL&P effective January 15, 2007 and of Northeast Utilities Foundation, Inc. effective January 1, 2005. Previously, Mr. McHale served as Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO from January 1, 2005 to December 31, 2008 and Vice President and Treasurer of NU, WMECO and PSNH from July 1998 to December 31, 2004.

Leon J. Olivier. Mr. Olivier was elected Executive Vice President and Chief Operating Officer of NU effective May 13, 2008; He also has served as Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007; a Director of PSNH and WMECO since January17, 2005 and a Director of CL&P since September 2001. Previously, Mr. Olivier served as Executive Vice President - Operations of NU from February 13, 2007 to May 12, 2008 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. Ms. Payne was elected Vice President - Accounting and Controller of NU effective February 13, 2007, and Vice President - Accounting and Controller of CL&P, PSNH and WMECO effective January 29, 2007. Previously, Ms. Payne served as 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. Mr. Robb was elected Senior Vice President, Enterprise Planning and Development of NUSCO on September 4, 2007. Previously, Mr. Robb served as 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; and Senior Vice President, Performance Management, Reliant Resources, Inc. from November 2002 to December 2003.

Charles W. Shivery. Mr. Shivery was elected Chairman of the Board, President and Chief Executive Officer of NU effective March 29, 2004; Chairman and a Director of CL&P, PSNH and WMECO effective January 19, 2007 and a Director of Northeast Utilities Foundation effective March 3, 2004. Previously, Mr. Shivery served as President (interim) of NU from January 1, 2004 to March 29, 2004; and President - Competitive Group of NU and President and Chief Executive Officer of NU Enterprises, Inc., from June 2002 through December 2003.

There are no family relationships between any executive officer and any Trustee or other executive officer of NU and none of the above executive officers serve as an executive officer pursuant to any agreement or understanding with any other person.

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**	
2008	First	$	31.15	$	24.01
	Second		27.74		25.12
	Third		28.03		24.52
	Fourth		25.97		19.15
2007	First	$	32.77	$	27.40
	Second		33.53		27.37
	Third		29.42		26.93
	Fourth		32.83		27.98

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, 2008.

As of January 31, 2009, there were 44,042 common shareholders of our company on record. As of the same date, there were a total of 176,230,893 common shares issued, including 643,860 unallocated Employee Stock Ownership Plan (ESOP) shares held in the ESOP trust.

Pursuant to NU parent's Shareholder Rights Plan (the "Plan"), NU parent distributed to shareholders of record as of May 7, 1999, a dividend in the form of one common share purchase right (a "Right") for each common share owned by the shareholder. The Rights and the Plan expired at the end of the 10-year term on February 23, 2009. NU parent's Board of Trustees adopted the Plan in 1999 to protect its shareholders in the event of an unsolicited bid to acquire the company. If triggered, it would have allowed shareholders other than the acquiror to purchase a specified number of additional shares at a 50 percent discount from the then current market price, thus encouraging the acquiror to negotiate a fair price for NU common shares with the Board. NU parent s Board of Trustees felt that renewal of the Plan was unnecessary at this time to protect shareholders' rights and accordingly decided to allow it to expire. The Board has the ability in its discretion to adopt a similar plan in the future but has no present intention of doing so.

On February 10, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on March 31, 2009, to shareholders of record as of March 1, 2009.

On October 14, 2008, our Board of Trustees declared a dividend of 21.25 cents per share, payable on December 31, 2008, to shareholders of record as of December 1, 2008.

On May 12, 2008, our Board of Trustees declared a dividend of 21.25 cents per share, payable on September 30, 2008, to shareholders of record as of September 1, 2008.

On April 8, 2008, our Board of Trustees declared a dividend of 20 cents per share, payable on June 30, 2008, to shareholders of record as of June 1, 2008.

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 as of 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.

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 "Combined Notes to Consolidated Financial Statements," within this Annual Report on Form 10-K.

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

During 2008 and 2007, CL&P approved and paid $106.5 million and $79.2 million, respectively, of common stock dividends to NU.

During 2008 and 2007, PSNH approved and paid $36.4 million and $30.7 million, respectively, of common stock dividends to NU.

During 2008 and 2007, WMECO approved and paid $39.7 million and $12.8 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 Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and share information)	**2008**	**2007**	**2006**	**2005**	**2004**
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 8,207,876	$ 7,229,945	$ 6,242,186	$ 6,417,230	$ 5,864,161
Total Assets	13,988,480	11,581,822	11,303,236	12,567,875	11,638,396
Total Capitalization (a)	7,293,960	6,667,920	5,879,691	5,595,405	5,293,644
Obligations Under Capital Leases (a)	13,397	14,743	14,425	13,987	14,806
Income Data:					
Operating Revenues	$ 5,800,095	$ 5,822,226	$ 6,877,687	$ 7,346,226	$ 6,480,684
Income/(Loss) from Continuing Operations	260,828	245,896	132,936	(256,903)	70,423
Income from Discontinued Operations	-	587	337,642	4,420	46,165
Income/(Loss) Before Cumulative Effects of Accounting Changes, Net of Tax Benefits	260,828	246,483	470,578	(252,483)	116,588
Cumulative Effects of	-	-	-	(1,005)	-

Accounting Changes, Net of Tax Benefits										
Net Income/(Loss)	$	260,828	$	246,483	$	470,578	$	(253,488)	$	116,588
Common Share Data:										
Basic Earnings/(Loss) Per Common Share:										
Income/(Loss) from Continuing Operations	$	1.68	$	1.59	$	0.86	$	(1.95)	$	0.55
Income from Discontinued Operations		-		-		2.20		0.03		0.36
Cumulative Effects of Accounting Changes, Net of Tax Benefits		-		-		-		(0.01)		-
Net Income/(Loss)	$	1.68	$	1.59	$	3.06	$	(1.93)	$	0.91
Fully Diluted Earnings/(Loss) Per Common Share:										
Income/(Loss) from Continuing Operations	$	1.67	$	1.59	$	0.86	$	(1.95)	$	0.55
Income from Discontinued Operations		-		-		2.19		0.03		0.36
Cumulative Effects of Accounting Changes, Net of Tax Benefits		-		-		-		(0.01)		-
Net Income/(Loss)	$	1.67	$	1.59	$	3.05	$	(1.93)	$	0.91
Basic Common Shares Outstanding (Average)		155,531,846		154,759,727		153,767,527		131,638,953		128,245,860

Fully Diluted Common Shares Outstanding (Average)	155,999,240	155,304,361	154,146,669	131,638,953	128,396,076
Dividends Per Share	$ 0.83	$ 0.78	$ 0.73	$ 0.68	$ 0.63
Market Price - Closing (high) (b)	$ 31.15	$ 33.53	$ 28.81	$ 21.79	$ 20.10
Market Price - Closing (low) (b)	$ 19.15	$ 26.93	$ 19.24	$ 17.61	$ 17.30
Market Price - Closing (end of year) (b)	$ 24.06	$ 31.31	$ 28.16	$ 19.69	$ 18.85
Book Value Per Share (end of year)	$ 19.38	$ 18.79	$ 18.14	$ 15.85	$ 17.80
Tangible Book Value Per Share (end of year)	$ 17.54	$ 16.93	$ 16.28	$ 13.98	$ 15.17
Rate of Return Earned on Average Common Equity (%)	8.8	8.6	18.0	(10.7)	5.1
Market-to-Book Ratio (end of year)	1.2	1.7	1.6	1.2	1.1
Capitalization:					
Common Shareholders Equity	41 %	44 %	48 %	43 %	44 %
Preferred Stock	2	2	2	2	2
Long-Term Debt (a)	57	54	50	55	54
	100 %	100 %	100 %	100 %	100 %

(a)

Includes portions due within one year, but excludes RRBs.

(b)

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

CL&P Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2008	2007	2006	2005	2004
Operating Revenues	$ 3,558,361	$ 3,681,817	$ 3,979,811	$ 3,466,420	$ 2,832,924
Net Income	191,158	133,564	200,007	94,845	88,016
Cash Dividends on Common Stock	106,461	79,181	63,732	53,834	47,074
Property, Plant and Equipment, net	5,089,124	4,401,846	3,634,370	3,166,692	2,824,877
Total Assets	8,336,118	7,018,099	6,321,294	5,765,072	5,306,913
Rate Reduction Bonds	378,195	548,686	743,899	856,479	995,233
Long-Term Debt (a)	2,270,414	2,028,546	1,519,440	1,258,883	1,052,891
Preferred Stock - Non-Redeemable	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	11,207	13,602	14,264	13,488	14,093

PSNH Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2008	2007	2006	2005	2004
Operating Revenues	$ 1,141,202	$ 1,083,072	$ 1,140,900	$ 1,128,427	$ 968,749
Net Income	58,067	54,434	35,323	41,739	46,641
Cash Dividends on Common Stock	36,376	30,720	41,741	42,383	27,186
Property, Plant and Equipment, net	1,580,985	1,388,405	1,242,378	1,155,423	1,031,703
Total Assets	2,628,833	2,106,969	2,071,276	2,294,583	2,205,374
Rate Reduction Bonds	235,139	282,018	333,831	382,692	428,769
Long-Term Debt (a)	686,779	576,997	507,099	507,086	457,190
Obligations Under Capital Leases (a)	1,931	1,141	1,356	498	712

WMECO Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	**2008**	**2007**	**2006**	**2005**	**2004**
Operating Revenues	$ 441,527	$ 464,745	$ 431,509	$ 409,393	$ 379,229
Net Income	18,330	23,604	15,644	15,085	12,373
Cash Dividends on Common Stock	39,706	12,779	7,946	7,685	6,485
Property, Plant and Equipment	624,205	559,357	526,094	499,317	468,884
Total Assets	1,048,489	991,088	988,693	945,996	922,472
Rate Reduction Bonds	73,176	86,731	99,428	111,331	122,489
Long-Term Debt (a)	303,868	303,872	261,777	259,487	207,684

(a)

Includes portions due within one year, but excludes RRBs.

Item 7.

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 related combined notes included in this Annual Report on Form 10-K. References in this Annual Report to "NU," "we," "us" and "our" refer to Northeast Utilities and its consolidated subsidiaries. All per share amounts are reported on a fully diluted basis.

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

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

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

Financial Condition and Business Analysis

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

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

Executive Summary

The following items in this executive summary are explained in more detail in this Annual Report:

Results, Strategy and Outlook:

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We earned $260.8 million, or $1.67 per share, in 2008, compared with $246.5 million, or $1.59 per share, in 2007. Results for 2008 included an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in 2008 were $290.6 million, or $1.86 per share.

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After payment of CL&P preferred dividends, our regulated companies, which consist of CL&P, Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), and Yankee Gas Services Company (Yankee Gas), earned $289.1 million, or $1.85 per share, in 2008, compared with $228.7 million, or $1.47 per share, in 2007. The 2008 results included earnings of $150.8 million in the distribution segment (which includes the generation segment of PSNH and gas distribution segment of Yankee Gas), and $138.3 million in the transmission segment. In 2007, our distribution segment earned $146.2 million and our transmission segment earned $82.5 million.

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Our competitive businesses, or NU Enterprises, Inc. (NU Enterprises), earned $13.1 million, or $0.08 per share, in 2008, compared with $11.7 million, or $0.08 per share, in 2007.

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NU parent and other companies recorded net expenses of $41.4 million, or $0.26 per share, in 2008, compared with net income of $6.1 million, or $0.04 per share, in 2007. Excluding the litigation settlement charge related to Con Edison, NU parent and other companies recorded net expenses of $11.6 million, or $0.07 per share, in 2008.

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In 2008, CL&P completed the final three of its four major transmission projects in southwest Connecticut. The projects were completed approximately $80 million below their $1.68 billion budget and the final project was completed approximately one year ahead of schedule. Also, in October 2008, CL&P and WMECO filed siting applications to build their portions of the $714 million Greater Springfield Reliability Project, which is the largest project within the New England East-West Solutions (NEEWS) series of projects. Refer to "Business Developments and Capital Expenditures - Regulated Companies - Transmission Segment" in this Management s Discussion and Analysis for further discussion.

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We project consolidated 2009 earnings of between $1.80 per share and $2.00 per share, including earnings of between $1.00 per share and $1.10 per share at our distribution segment, between $0.85 per share and $0.90 per share at our transmission segment and between $0.00 per share and $0.05 per share at our remaining competitive businesses, and net expenses of $0.05 per share at NU parent and other companies. This projection assumes the issuance of between $250 million and $300 million of additional equity in mid-2009. Our 2009 forecast reflects our expectations of lower electric sales and higher pension and uncollectible expense than what we experienced in 2008, due to current economic conditions.

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

Legal, Regulatory and Other Items:

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On January 28, 2008, the Connecticut Department of Public Utility Control (DPUC) approved an increase in CL&P s annual distribution rates of $77.8 million, effective February 1, 2008, and an incremental $20.1 million annual increase, effective February 1, 2009.

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

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On March 24, 2008, the Federal Energy Regulatory Commission (FERC) issued a rehearing order confirming its initial decision setting the base return on equity (ROE) for transmission projects for the New England transmission owners. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC's earlier decision granting a 100 basis point adder for transmission projects that are part of the New England Independent System Operator (ISO-NE) Regional System Plan and are completed and on line by December 31, 2008. In 2008, we added $6 million ($4.9 million for CL&P) in transmission segment earnings related to this order.

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On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund to customers approximately $5.8 million in previous recoveries through Yankee Gas' Purchased Gas Adjustment (PGA) clause. Yankee Gas results for 2008 reflect an after-tax charge of $3.5 million associated with that decision.

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On July 16, 2008, the Massachusetts Department of Public Utilities (DPU) issued a decision requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. On September 2, 2008, WMECO notified the DPU that it expects to file its next distribution rate case in mid-2010 to be effective January 1, 2011. The distribution rate case will include a proposal to fully decouple distribution revenues from kilowatt-hour (KWH) sales.

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On July 17, 2008, the FERC confirmed the 100 basis point incentive ROE for the Middletown-Norwalk transmission project and approved an additional 50 basis points, capped at the overall ROE limit, to the ROE CL&P will earn on the advanced technology aspects of its 24-mile underground portion of the 69-mile project, which entered service in December 2008. This decision adds approximately $0.9 million to CL&P s annual transmission segment earnings beginning in 2009.

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In October 2008, CL&P had entered into contracts for differences (CfDs) with developers of three peaking generation units approved by the DPUC. These units will have a total of approximately 500 megawatts (MW) of peaking capacity. As directed by the DPUC, CL&P and The United Illuminating Company (UI) entered into a sharing agreement, whereby CL&P is responsible for

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80 percent and UI for 20 percent of the net costs or benefits of these CfDs. CL&P s portion of the costs and benefits will be paid by or refunded to its customers.

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On November 17, 2008, the FERC issued an order granting incentives and rate amendments to National Grid USA and us for NEEWS transmission upgrade components. Our portion of these components is currently estimated to comprise about $1.41 billion of the total $1.49 billion cost estimate for our portion of NEEWS. The approved incentives included cash recovery through rates for 100 percent construction work in progress (CWIP), an incentive ROE of 12.89 percent and recovery of prudently incurred costs associated with project elements that may be cancelled for reasons outside of our control or National Grid USA's control.

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On December 11, 2008, a major ice storm struck portions of New England causing approximately $100 million of damage to PSNH's, WMECO's and CL&P's distribution systems. This was the most severe ice storm in PSNH's history, and most of the $100 million in damages was to its system. CL&P s system suffered the least amount of damage from the storm. Some of these costs are covered by insurance, a small portion was expensed in 2008 and the balance should be recoverable in future rates and has been deferred or capitalized. None of the companies experienced a material impact to their results of operations from this storm.

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On December 12, 2008, NU and NSTAR submitted a joint petition for a declaratory order to the FERC to allow NU and NSTAR to enter into a bilateral transmission services agreement with H.Q. Energy Services (U.S.) Inc. (HQUS), a wholly-owned subsidiary of Hydro-Québec. Under such an agreement, NU and NSTAR would sell 1,200 MW of firm electric transmission service over a newly constructed, participant-funded transmission tie line connecting New England with the Hydro-Québec system in order for HQUS to sell and deliver into New England this same amount of firm electric power from Canadian low-carbon energy resources. NU, NSTAR and HQUS have signed memoranda of understanding to develop this transmission project on an exclusive basis. Our portion of this project is currently estimated to cost approximately $525 million. Refer to "Business Development and Capital Expenditures" in this Management s Discussion and Analysis for further discussion.

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On January 15, 2009, the DPUC issued a final decision reversing its December 2005 draft decision regarding CL&P s proposed methodology to calculate the variable incentive portion of its transition service procurement fee in 2004. The final decision concluded that CL&P was not eligible for this procurement incentive. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings. A $5.8 million pre-tax charge (approximately $3.5

million net of tax) was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers was established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

Liquidity:

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

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Our cash capital expenditures totaled $1.3 billion in 2008, compared with $1.1 billion in 2007. We were successful in meeting our extensive 2008 capital plan. In 2009, we expect cash capital expenditures to be approximately $880 million, primarily because of lower transmission capital expenditures at CL&P.

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We issued $760 million of long-term debt in 2008 at rates of between 5.65 percent and 6.9 percent, and $250 million in February 2009 at a rate of 5.5 percent. We expect further external financings totaling $400 million to $450 million in mid-2009 (or earlier depending on market opportunities), including approximately $150 million of long-term debt by PSNH, subject to regulatory approval, and between $250 million and $300 million of additional equity by NU parent. Refer to "Liquidity" in this Management s Discussion and Analysis for further discussion.

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On June 30, 2008, due to the availability and lower relative cost of other liquidity sources, CL&P chose to terminate the arrangement under which CL&P could sell to a financial institution up to $100 million of accounts receivable and unbilled revenues.

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After rate reduction bond (RRB) payments included in financing activities, we had cash flows provided by operations in 2008 of $418.5 million, which represented an increase of $429.8 million from 2007. This increase was primarily due to the absence in 2008 of approximately $400 million in tax payments in 2007 related to the 2006 sale of the competitive generation business, partially offset by the litigation settlement payment to Con Edison of $49.5 million in 2008. Refer to "Liquidity - Consolidated" in this Management s Discussion and Analysis for further discussion.

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In 2009, we project operating cash flows of approximately $500 million, after repayment of RRBs. This projection does not include any contributions to our pension plan, as they are not required to be paid in 2009. The primary reasons for the projected increase from 2008 are that our major southwest Connecticut transmission projects will be fully reflected in rates in 2009 due to their completion in the second half of 2008 and that the 2008 Con Edison settlement payment is absent in 2009, partially offset by the payment in 2009 of major storm costs incurred in December 2008 that likely will not be fully recovered from customers in 2009. Excluding potential contributions to our pension plan, we currently project our internally-generated cash flows to grow to approximately $1 billion by 2013.

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As of February 25, 2009, we had approximately $466 million of externally invested cash. At this time, we also had approximately $51 million of borrowing availability on our revolving credit lines, excluding the remaining unfunded commitment of Lehman Brothers Commercial Bank (LBCB) (refer to "Liquidity - Impact of Financial Market Conditions" for further discussion).

Overview

Consolidated: We earned $260.8 million, or $1.67 per share, in 2008, compared with $246.5 million, or $1.59 per share, in 2007 and $470.6 million, or $3.05 per share, in 2006. Results for 2008 included an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in 2008 were $290.6 million, or $1.86 per share. Results for 2006 included an after-tax gain of $314 million, or $2.03 per share, associated with the sale of our competitive generation business, and a reduction in income tax expense at CL&P of $74 million, or $0.48 per share, pursuant to a PLR received from the IRS. Results in 2007 and 2006 included discretionary pre-tax donations to the NU Foundation (Foundation) of $3 million and $25 million, respectively. There was no such contribution in 2008. A summary of our earnings, which also reconciles the non-GAAP measures of consolidated non-GAAP earnings and EPS, as well as EPS by segment, to the most directly comparable GAAP measures of consolidated net income and fully diluted EPS, for 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,					
	2008		**2007**		**2006**	
(Millions of Dollars, except per share amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income (GAAP)	$ 260.8	$ 1.67	$ 246.5	$ 1.59	$ 470.6	$ 3.05
Regulated companies	$ 289.1	$ 1.85	$ 228.7	$ 1.47	$ 183.3	$ 1.19
	13.1	0.08	11.7	0.08	(102.7)	(0.66)

Competitive businesses						
NU parent and other companies	(11.6)	(0.07)	6.1	0.04	2.0	0.01
Non-GAAP earnings	290.6	1.86	246.5	1.59	82.6	0.54
Con Edison litigation charge	(29.8)	(0.19)	-	-	-	-
Gain on sale of competitive business	-	-	-	-	314.0	2.03
Reduction in income tax expense (PLR)	-	-	-	-	74.0	0.48
Net Income (GAAP)	$ 260.8	$ 1.67	$ 246.5	$ 1.59	$ 470.6	$ 3.05

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

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

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

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

CL&P s 2008 distribution segment earnings were $8.6 million higher than 2007 primarily due to higher distribution revenues resulting from a distribution rate increase effective February 1, 2008, a settlement of federal tax matters, a lower effective income tax rate, and higher other revenues resulting from financial incentives under Connecticut's "Act Concerning Energy Independence" to promote distributed generation and demand side management. These items were partially offset by a 3.7 percent decline in sales, higher operating costs, including full-year storm expenses, maintenance expenses, and interest expense, a $5.8 million pre-tax charge to refund the 2004 procurement incentive fee that was recognized in 2005 earnings, and losses on investments in the Trust Under

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Supplemental Executive Retirement Plan ("supplemental benefit trust"). CL&P s distribution segment Regulatory ROE was 7.5 percent in 2008 and 7.9 percent in 2007. We expect CL&P s distribution segment Regulatory ROE in 2009 will be approximately 7 percent.

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

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

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

For the distribution segment of our regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric KWH sales and Yankee Gas firm natural gas sales for 2008 as compared to 2007 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Electric			
	CL&P	**PSNH**	**WMECO**	**Total**

	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Decrease	We Norr Perc Dec
Residential	(4.1)%	(2.7)%	(2.2)%	(1.0)%	(3.1)%	(2.1)%	(3.6)%	
Commercial	(1.3)%	(0.7)%	(1.2)%	(0.4)%	(2.6)%	(2.1)%	(1.4)%	
Industrial	(9.8)%	(9.3)%	(6.1)%	(5.4)%	(8.7)%	(8.5)%	(8.6)%	
Other	(3.2)%	(3.2)%	2.2 %	2.2 %	(14.6)%	(14.6)%	(3.7)%	
Total	(3.7)%	(2.8)%	(2.5)%	(1.6)%	(4.2)%	(3.5)%	(3.5)%	

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

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

*Amounts may not total due to rounding of GWH.

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

Changes in electric sales, however, have less of an impact on the earnings of the electric companies than in prior years because non-distribution rate revenues, which represented approximately 76 percent of electric company revenues in 2008, are tracked and reconciled to actual costs. Non-distribution rate revenues include the energy, stranded cost, retail transmission and federally mandated congestion costs (FMCC) charges and other components of rates. For non-distribution rate revenues, the only impact to earnings is from carrying costs on over- or underrecoveries. With respect to the distribution revenues, about two-thirds of CL&P's and WMECO's revenues and about one-half of

PSNH's revenues are recovered through charges that are not dependent on overall sales volumes, such as the customer charge and the demand charge.

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

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

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

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

million in 2007. The higher competitive business earnings in 2006 were attributable to the $314 million after-tax gain on the sale of the competitive generation business, partially offset by $70.3 million of losses at the retail marketing business, which was sold on June 1, 2006.

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

Future Outlook

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

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

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

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

Business Development and Capital Expenditures

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

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

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

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

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

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

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

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

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

*

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

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

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The 69-mile, 345 KV/115 KV transmission project from Middletown to Norwalk, Connecticut (Middletown-Norwalk) that was constructed jointly with UI. CL&P's portion of this project cost approximately $950 million, $100 million lower than the earlier estimate of $1.05 billion primarily due to a decrease in capitalized financing costs because of the earlier-than-expected in service date. Of the $950 million, approximately $334 million was capitalized in 2008. The

45-mile overhead section of the project entered service on August 28, 2008. The 24-mile underground section entered service on December 16, 2008.

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The two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), which entered service ahead of schedule on November 11, 2008. This project cost approximately $239 million, which is $16 million higher than the previous estimate due to increased construction costs related to underground obstacles. Of the $239 million, approximately $102 million was capitalized in 2008.

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The 138 KV, 11-mile undersea transmission project between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable), which was completed in September 2008. CL&P's 51 percent portion of the project with Long Island Power Authority is estimated to be approximately $78 million, which represents a $7 million increase over the previous estimate. Of the $78 million, approximately $33 million was capitalized in 2008.

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

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

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

Our second major NEEWS project is the Interstate Reliability Project, which is being designed and built in coordination with National Grid USA. CL&P's share of this project includes an approximately 40-mile, 345 KV line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid USA is designing. We expect CL&P's share of this project to cost approximately $250 million. Municipal consultations concluded in November 2008, and CL&P plans to file siting

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applications with Connecticut regulators by the third quarter of 2009 with construction beginning as early as late 2010. We currently expect the project to be placed in service as early as 2012.

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

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

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

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

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

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

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

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

Liquidity

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

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

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

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

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

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

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

On July 29, 2008, Moody's changed the outlook of Yankee Gas to stable from negative and affirmed the company's Baa2 corporate credit rating. On August 8, 2008, Fitch affirmed all of its ratings and outlooks on NU parent, CL&P, PSNH and WMECO. In late October 2008, S&P affirmed all of its ratings and outlooks on NU parent, CL&P, PSNH and WMECO. On November 5, 2008, S&P raised CL&P's unsecured debt rating to BBB from BBB- as a result of a comprehensive review of the unsecured ratings of United States investment grade utilities. S&P's ratings on CL&P's bonds and preferred stock were unaffected.

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

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

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

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

Cash capital expenditures included on the accompanying consolidated statements of cash flows and described in the liquidity section of this Management's Discussion and Analysis do not include amounts incurred on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. Our cash capital expenditures totaled $1.3 billion in 2008, compared with $1.1 billion in 2007 and $872.2 million in 2006. Our cash capital expenditures in 2008 included $849.5 million by CL&P, $238.9 million by PSNH, $78.3 million by WMECO, $58.3 million by Yankee Gas, and $30.4 million by other NU subsidiaries. Our cash capital expenditures in 2007 included $826.2 million by CL&P, $167.7 million by PSNH, $47.3 million by WMECO, $57.6 million by Yankee Gas, and $16 million by other NU subsidiaries. The increase in our aggregate cash capital expenditures was primarily the result of higher distribution segment capital expenditures.

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

Regulated Companies: The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million including the commitment of LBCB (as further discussed below), which expires on November 6, 2010. There were $315 million of borrowings outstanding under this facility at December 31, 2008 ($188 million for CL&P, $45.2 million for PSNH, $29.9 million for WMECO). The weighted-average interest rate on these short-term borrowings at December 31, 2008 was 3.35 percent, which is based on a variable rate plus an applicable margin based on our credit ratings. We had approximately $1 million of borrowing availability on this facility as of February 25, 2009, excluding LBCB's remaining unfunded commitment. As stated above, we also had approximately $466 million of externally invested cash at February 25, 2009.

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

Our debt agreements provide that NU and certain of its subsidiaries, including CL&P, PSNH and WMECO, must comply with certain financial and non-financial covenants as are customarily included in such agreements, including a consolidated debt to capitalization ratio. The parties to these agreements currently are and expect to remain in compliance with these covenants. Refer to Note 2, "Short-Term Debt," and Note 11, "Long-Term Debt," to our consolidated financial statements included in this Annual Report on Form 10-K for further discussion of material terms and conditions of our outstanding debt agreements.

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

to fund common dividends, the incremental cash increase is relatively small and we continue to have a modest payout ratio relative to peer companies.

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

In addition to the revolving credit facilities described above, we intend to access the capital markets, as appropriate, to fund our capital projects or otherwise meet funding needs. The availability and cost of external financings, including our expected financings in 2009 described below, will be affected by our financial condition and the then-current financial market conditions. There can be no assurance that the cost or availability of future borrowings, if any, will not be impacted by recent or future capital market disruptions. Refer to Item 1A, "Risk Factors," in this Annual Report on Form 10-K for further discussion.

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

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

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

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

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

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

For the 2009 pension plan year, it is likely that we will also be required to make a pension plan contribution unless there is a change in current funding requirements or a very significant recovery in the financial markets. Also, assuming that the pension plan assets earn the long-term rate of return of 8.75 percent and discount rates remain constant, we currently estimate that we could be required to make an additional pre-tax contribution for the 2009 plan year in 2010 of between $150 million and $200 million. Contributions for the 2009 plan year would be made quarterly beginning in the second quarter of 2010. If significant contributions for 2009 or future pension plan years are required and there is no change in regulatory recovery mechanisms, then there will likely be an impact on the timing and amount of our future debt and equity financings. The majority of our pension expense is included in rates charged to customers of our regulated companies.

Transmission Rate Matters and FERC Regulatory Issues

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

Transmission - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under the ISO-NE FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Schedule 21 - NU rate schedules to recover fees for transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The Schedule 21 - NU rate, which we administer, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 100 percent of the CWIP that is included in rate base on the NEEWS projects discussed below. The Schedule 21 - NU rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that we recover all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and Schedule 21 - NU rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to customers. At December 31, 2008, the Schedule 21 - NU rates were in a total underrecovery position of $4.6 million ($3.8 million for CL&P), which will be collected from customers in mid-2009.

FERC ROE Decision: On March 24, 2008, the FERC issued a rehearing order confirming its initial decision setting the base ROE for transmission projects for the New England transmission owners. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC's earlier decision granting a 100 basis point adder for transmission projects that are part of the ISO-NE Regional System Plan and are completed and on line by December 31, 2008. In 2008, we added $6 million ($4.9 million for CL&P) in transmission segment earnings related to this order. This order has been appealed to the D.C. Circuit Court of Appeals by numerous state regulators and consumer advocates. The Court has set a schedule for briefing to conclude by the end of the second quarter of 2009. No date has been set for arguments.

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

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

On August 18, 2008, CL&P made a compliance filing with the FERC detailing the costs associated with the underground cables and supporting facilities of the Middletown-Norwalk project, which qualified as advanced technology. On September 8, 2008, the DPUC

filed a motion to reject and protest our compliance filing, stating we did not provide sufficient information. There is no specific deadline for the FERC to respond to this motion. Our response to the protest has been filed at the FERC.

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

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

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

Legislative Matters

Environmental Legislation: The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by ten northeastern and mid-Atlantic states, including Connecticut, New Hampshire and Massachusetts, to develop a regional program for stabilizing and reducing carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating plants. RGGI proposes to stabilize CO_2 emissions at 2009 levels and reduce them by 10 percent from these levels by 2018. RGGI is composed of individual CO_2 budget trading programs in each of the participating states. Each participating state s CO_2 budget trading program establishes its respective share of the regional cap, and each state will issue CO_2 allowances in a number equivalent to its portion of the regional cap. Each CO_2 allowance represents a permit to emit one ton of CO_2 in a specific year. The RGGI states will distribute CO_2 allowances primarily through regional auctions. Regulated power generators are able to purchase CO_2 allowances issued by any of the participating states to demonstrate compliance with the RGGI program of the state governing their generating plants. Taken together, the individual participating state programs will function as a single regional compliance market for carbon emissions.

Connecticut adopted regulations in July 2008, which established an auction clearing price threshold of $5 per CO_2 allowance, above which price all auction proceeds will be rebated to customers. For proceeds up to the clearing price threshold, 69.5 percent will be directed to the conservation and load management programs managed by the state s utilities in conjunction with the Energy Conservation Management Board. Seventy-five percent of the RGGI auction proceeds directed to conservation and load management programs will be allocated to CL&P s programs. Because CL&P does not own any generating assets, it is not required to acquire CO_2 allowances; however, CO_2 allowance costs will likely be included in wholesale rates charged to CL&P in standard offer type contracts.

Massachusetts passed legislation in July 2008 that did not set an auction clearing price threshold for RGGI auctions. This law requires 80 percent of RGGI auction proceeds to be allocated to utility energy efficiency and demand response programs. Because WMECO does not own any generation assets, it is not required to acquire any CO_2 allowances; however, CO_2 allowance costs will likely be included in wholesale rates charged to WMECO in standard offer type contracts.

New Hampshire passed legislation in June 2008 that set an auction clearing price threshold of $6 per CO_2 allowance in 2009, above which all auction proceeds will be rebated to customers. Proceeds below the threshold are to be used for demand response and energy efficiency programs.

The first regional auction of RGGI CO_2 allowances took place on September 25, 2008. At the auction, more than 12.5 million CO_2 allowances were sold at the clearing price of $3.07 per CO_2 allowance. The second regional auction was held on December 17, 2008, and more than 31.5 million allowances were sold at a clearing price of $3.38 per CO_2 allowance. Auctions are scheduled for March, June, September and December 2009.

PSNH anticipates that its generating units will emit between 4 million and 5 million tons of CO_2 per year after taking into account the operation of PSNH s Northern Wood Power wood-burning generating plant, which under the RGGI formula, decreased PSNH s responsibility for reducing fossil-fired CO_2 emissions by approximately 425,000 tons per year, or almost ten percent. New Hampshire legislation provides up to 2.5 million banked CO_2 allowances per year for PSNH s fossil fueled generating plants during the 2009 to 2011 compliance period. These banked CO_2 allowances will initially comprise approximately one-half of the yearly CO_2 allowances required for PSNH s generating plants to comply with RGGI, and such banked allowances will decrease over time. PSNH expects to satisfy its remaining RGGI requirements by purchasing CO_2 allowances at auction or in the market and has purchased allowances in the first two auctions. The cost of complying with RGGI requirements is recoverable from PSNH customers.

New Hampshire:

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

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

Massachusetts:

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

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Removes the cap on utility expenditures for EE and demand response (DR). Requires utilities to file three-year EE and DR plans with a newly created Energy Efficiency Council;

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Requires utilities to sign long-term contracts for renewable resources;

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Allows each utility to own and operate up to 50 MW of solar generation;

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Requires utilities to file a plan with the DPU for a smart grid pilot; and

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Increases penalties for failure to meet service quality standards from 2 percent of transmission and distribution revenues to 2.5 percent.

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

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

Regulatory Developments and Rate Matters

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

Regulated Companies Transmission Revenues - Retail Rates: A significant portion of our transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. Each of these companies has a retail transmission cost tracking mechanism as part of its rates, which allows them to charge their retail customers for transmission costs on a timely basis.

Forward Capacity Market: On December 1, 2006, a FERC-approved settlement agreement providing for an auction-based forward capacity market (FCM) mechanism was implemented and the payment of fixed compensation to generators through May 31, 2010 began. The first forward capacity auction concluded in early February 2008 for the capacity year of June 2010 through May 2011. The bidding reached the established minimum of $4.50 per kilowatt-month with 2,047 MW of excess remaining capacity, which resulted in an effective capacity price of $4.25 per kilowatt-month compared to the previously established price of $4.10 per kilowatt-month for the capacity year preceding June 2010. The second auction concluded on December 10, 2008 for the capacity year of June 2011 through May 2012. The bidding reached the established minimum of $3.60 per kilowatt-month with 4,755 MW of excess remaining capacity, which resulted in an effective capacity price of $3.12 per kilowatt-month. These costs are recoverable in all jurisdictions through the currently established rate structures.

Connecticut - CL&P:

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

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

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

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

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

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

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under Standard Service (SS) rates, and large commercial and industrial customers who do not choose competitive suppliers are served under Last Resort Service (LRS) rates. Effective January 1, 2009, the DPUC approved an increase to CL&P's total average SS rate of approximately 2.4 percent and a decrease to CL&P's total average LRS rate of approximately 5.9 percent. The energy supply portion of the total average SS rate increased from 11.852 cents per KWH to 12.316 cents per KWH. The energy supply portion of the total average LRS rate decreased from 12.667 cents per KWH to 11.738 cents per KWH. Effective April 1, 2009, the DPUC approved a decrease to CL&P s total average LRS rate of approximately 22 percent, which was a result of the energy supply portion decreasing to 8.207 cents per KWH from January 1, 2009. CL&P is fully and timely recovering the costs of its SS and LRS services.

CTA and SBC Reconciliation: On March 31, 2008, CL&P filed with the DPUC its 2007 Competitive Transition Assessment (CTA) and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million, which has been recorded as a decrease to the CTA regulatory asset on the accompanying consolidated balance sheet. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million, which has been recorded as a regulatory asset on the accompanying consolidated balance sheet. On December 3, 2008, the DPUC issued a final decision in this docket that approved the 2007 CTA and SBC reconciliation with minor modifications. The decision referred to a potential change in the CTA rate effective January 1, 2009, when new rates were to be determined for all CL&P rate components. By letter dated December 23, 2008, the DPUC approved CL&P s recommendation to slightly decrease the base CTA rate and to establish a separate CTA refund credit beginning January 1, 2009. The CTA refund credit is intended to return to customers over a twelve month period a projected 2008 CTA overrecovery of $46.2 million, plus $1.8 million of incremental distribution revenues attributable to accelerating CL&P s previously allowed 2009 distribution rate increase from a start date of February 1, 2009 to January 1, 2009. The DPUC also approved an increase in the SBC rate to bill an additional $11.7 million in 2009, which should enable CL&P to fully recover 2009 SBC expenses plus expenses that were underrecovered in prior periods.

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

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

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

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

Connecticut-Yankee Gas:

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

New Hampshire:

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

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

ES and SCRC Reconciliation and Rates: On May 1, 2008, PSNH filed its 2007 default energy service (ES) and stranded cost recovery charge (SCRC) reconciliation with the NHPUC, whose evaluation includes a prudence review of PSNH's generation activities. During 2007, ES and SCRC revenues exceeded ES and SCRC costs by $1.4 million and $6.8 million, respectively, and were deferred as a

regulatory liability to be refunded to customers. On November 19, 2008, PSNH and the NHPUC Staff submitted a settlement agreement that resolved all outstanding issues. The NHPUC issued an order dated January 16, 2009 that accepted the settlement as filed. The settlement agreement and subsequent order did not have a material adverse impact on PSNH's financial position or results of operations. PSNH expects to file its 2008 ES and SCRC reconciliation with the NHPUC by May 1, 2009. We do not expect the outcome of the NHPUC review to have a material adverse impact on PSNH's financial position or results of operations.

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

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

Major Storm Costs Reserve: On December 11, 2008, a major ice storm struck portions of New England, severely damaging PSNH s distribution system. This was the most severe ice storm in PSNH s history. Of the 440,000 New Hampshire homes and businesses that lost power, 322,000 were served by PSNH. Restoration operations commenced on December 11, 2008 and were substantially completed by December 25, 2008. PSNH utilized its own line crews, local contractors, line crews from other NU subsidiaries and numerous other line crews from the eastern United States and Canada.

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

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

Massachusetts:

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

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

Transition Cost Reconciliations: On June 20, 2008, the DPU issued its final decision on WMECO s 2005 and 2006 transition cost reconciliations, which resulted in a pre-tax charge of $1.6 million to WMECO s 2008 consolidated statements of income. The DPU ordered WMECO to use a ROE of 11 percent, and not the allowed ROE of 9.85 percent in 2005 and 2006, for purposes of calculating

carrying cost credits for customers on the stranded cost deferrals. In addition, the DPU ordered WMECO not to combine certain overrecoveries and underrecoveries but instead to keep them separate and to calculate carrying costs on certain balances using a ROE of 11 percent and to use customer deposit rates on other balances. The impacts of this order on WMECO's calculations of the 2007 and year to date 2008 transition cost reconciliations were recorded in the second quarter of 2008.

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

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

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

Transfer of Transmission Assets: On December 15, 2008, the FERC approved the transfer of $4 million in transmission related assets of our wholly owned subsidiaries' HWP and HP&E to WMECO, which occurred on December 31, 2008. After certain routine regulatory filings, HWP and HP&E will no longer be FERC-regulated entities.

Contingent Matters:

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

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

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

Deferred Contractual Obligations

We have decommissioning and plant closure cost obligations to Connecticut Yankee Atomic Power Company (CYAPC), Yankee Atomic Electric Company (YAEC) and Maine Yankee Atomic Power Company (MYAPC) (Yankee Companies), which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including our electric utility subsidiaries. These companies recover these costs through state regulatory commission-approved retail rates. A summary of each of our subsidiary s ownership percentage in the Yankee Companies at December 31, 2008 is as follows:

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

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

CYAPC, YAEC and MYAPC are currently collecting amounts that we believe are adequate to recover the remaining decommissioning and closure cost estimates for their respective plants. We believe CL&P and WMECO will recover their shares of these decommissioning and closure obligations from their customers. PSNH has recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. In December 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

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

The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, we believe that any net settlement proceeds we receive would be incorporated into FERC-approved recoveries, which would be passed on to our customers through reduced charges.

NU Enterprises Divestitures

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

Wholesale Marketing: During 2008 Select Energy continued to manage its remaining PJM power pool wholesale sales contract and its related supply contracts, which expired on May 31, 2008, and its long-term wholesale sales contract with the New York Municipal Power Agency (NYMPA), an agency comprised of municipalities, and related supply contracts, that expires in 2013. These contracts are derivatives that have been marked to market through earnings. In addition to the NYMPA-related contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to purchase and operate the output of a certain generating facility in New England through 2012. As a non-derivative contract, the fair value of the contract has not been reflected on the balance sheet, and the contract has not been marked to market.

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

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

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

In connection with the sale of the retail marketing business, the competitive generation business and certain of the energy services businesses, we provided various guarantees and indemnifications to the purchasers of those businesses. See Note 7F, "Commitments and Contingencies - Guarantees and Indemnifications," to the consolidated financial statements for information regarding these items.

NU Enterprises Contracts

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

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

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

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

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

The methods Select Energy used to determine the fair value of its wholesale derivative contracts are identified and segregated in the table of fair value of wholesale derivative contracts at December 31, 2008 and 2007. A description of each method is as follows: 1) prices actively quoted primarily represent NYMEX futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards and options, including bilateral contracts for the purchase or sale of electricity, and are marked to the mid-point of bid and ask market prices. The mid-points of market prices are adjusted to include all applicable market information, such as historical experience with intramonth price volatility and bilateral contract prices in illiquid periods. Currently, Select Energy also has a derivative contract for which a portion of the contract's fair value is determined based upon a model. The model utilizes natural gas prices and a heat rate conversion factor to determine off-peak electricity prices for one New York routinely quoted hub zone for 2013. For the balance of hub zones, broker quotes for electricity prices are generally available on-peak through 2013 and off-peak through 2012.

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

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

(Millions of Dollars)	**Fair Value of Wholesale Contracts at December 31, 2008**			
Sources of Fair Value	**Maturity Less than One Year**	**Maturity of One to Four Years**	**Maturity in Excess of Four Years**	**Total Fair Value**
Prices actively quoted	$ (10.1)	$ (7.3)	$ (1.2)	$ (18.6)
Prices provided by external sources	(2.7)	(21.2)	(10.0)	(33.9)
Model-based [1]	(1.7)	(6.7)	(3.0)	(11.4)
Totals	$ (14.5)	$ (35.2)	$ (14.2)	$ (63.9)

(1)

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

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

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

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

(1)

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

(2)

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

For further information regarding Select Energy's derivative contracts, see Note 3, "Derivative Instruments," to the consolidated financial statements.

Counterparty Credit: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in Select Energy establishing credit limits prior to entering into contracts. The appropriateness of these limits is subject to our continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. At December 31, 2008, approximately 99 percent of Select Energy's counterparty credit exposure to wholesale counterparties was non-rated, and approximately one percent was collateralized. The bulk of the non-rated credit exposure is comprised of one counterparty, which is a non-rated public entity that we have assessed as creditworthy. To date, this counterparty has met all of its contractual obligations.

Off-Balance Sheet Arrangements

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

Competitive Businesses: We have various guarantees and indemnification obligations outstanding on behalf of former subsidiaries in connection with the exit from our competitive businesses. See Note 7F, "Commitments and Contingencies - Guarantees and Indemnifications," to the consolidated financial statements for information regarding the maximum exposure and amounts recorded under these guarantees and indemnification obligations.

Enterprise Risk Management

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

Critical Accounting Policies and Estimates

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

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

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

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

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

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

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

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

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

As of January 1, 2008, we applied SFAS No. 157 to our regulated and unregulated companies derivative contracts that are recorded at fair value and to the marketable securities held in our supplemental benefit trust and WMECO s spent nuclear fuel trust. We have also applied SFAS No. 157 to valuations of investments in our pension and PBOP plans as of December 31, 2008. Implementing SFAS No. 157 for our marketable securities expanded our financial statement disclosures, but did not affect the recorded fair value of investments.

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

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

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

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

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

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

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

Changes in fair value of the remaining wholesale marketing contracts of our unregulated businesses are recorded in fuel, purchased and net interchange power on the accompanying consolidated statements of income. For the year ended December 31, 2008, there were net unrealized gains of $4.3 million ($7 million pre-tax), related to the valuation of these contracts. There were net realized gains of $3 million ($5 million pre-tax) for the year ended December 31, 2008. Key drivers of variability in fair values include changes in energy prices and expected volumes under the contracts We utilize judgments in estimated expected volumes that are dependent on a number of factors including options exercised, customer utilization, weather and availability of other power sources to our counterparty. The valuations of our derivative contracts are highly sensitive to changes in market prices of commodities. See Item 7a, "Quantitative and Qualitative Disclosures about Market Risk," included in this Annual Report on Form 10-K for a sensitivity analysis of how changes in the prices of commodities would impact earnings.

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

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

Our regulated and unregulated business activities that result in the recognition of derivative assets create exposures to credit risk of energy marketing and trading counterparties. At December 31, 2008, we had $273.2 million ($245.8 million related to CL&P) of regulated company and NU parent derivative assets that are contracted with multiple entities, of which $125.5 million ($104.7 million related to CL&P) is contracted with investment grade entities, $4.6 million is contracted with a government-backed entity, $131.4 million related to CL&P is contracted with a non-rated subsidiary of an investment grade company and the remainder are contracted with multiple other counterparties. We consider the credit ratings of these companies in our valuation of derivative assets and we use published probability of default indices based on the credit ratings of the counterparties to discount the value of the derivative asset. Changes in our counterparties   credit impact our ability to collect the derivative asset. Our derivative assets are primarily related to our regulated companies. Credit losses on regulated company contracts would not affect our earnings because these entities are cost-of-service regulated companies and costs of these contracts are recoverable from our customers. In addition, we consider our own credit rating in the valuation of derivative liabilities. Adjusting our unregulated derivative liabilities to incorporate our credit risk had an after-tax impact of $0.7 million on the fair value of our derivative liability and net income for the year ended December 31, 2008. Our regulated companies derivative assets and liabilities were also reduced to reflect the impact of our counterparties   credit risk and our own credit risk on fair values, with no effect on net income.

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

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

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

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

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

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

Pre-tax periodic pension expense for the Pension Plan was $2.4 million, $17.4 million and $52.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. The pension expense amounts exclude one-time items such as Pension Plan curtailments and termination benefits. The pre-tax net PBOP Plan cost, excluding curtailments and termination benefits, was $36.2 million, $38.4 million and $50.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Long-Term Rate of Return Assumptions: In developing our expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, we evaluated input from actuaries and consultants, as well as long-term inflation assumptions and our historical 25-year compounded return of 11 percent. Our expected long-term rates of return on assets are based on certain target asset allocation assumptions. We believe that 8.75 percent is an appropriate aggregate long-term rate of return on Pension Plan and PBOP Plan assets (life assets and non-taxable health assets) and 6.85 percent for PBOP health assets, net of tax, for 2008. We will continue to evaluate these actuarial assumptions, including the expected rate of return, at least annually and will adjust the appropriate assumptions as necessary. The Pension Plan s and PBOP Plan s target asset allocation assumptions and expected long-term rates of return assumptions by asset category are as follows:

	At December 31,			
	Pension Benefits 2008 and 2007		Postretirement Benefits 2008 and 2007	
	Target Asset Allocation	**Assumed Rate of Return**	**Target Asset Allocation**	**Assumed Rate of Return**
Equity Securities:				
United States	40%	9.25%	55%	9.25%
Non-United States	17%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	2%	10.25%
Private	8%	14.25%	-	-
Debt Securities:				
Fixed income	25%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%
Real Estate	5%	7.50%	-	-

The actual asset allocations at December 31, 2008 and 2007 approximated these target asset allocations. We routinely review the actual asset allocations and periodically rebalance the investments to the targeted asset allocations when appropriate. For information regarding actual asset allocations, see Note 5A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements.

Pension and other postretirement benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and postretirement benefit payments. Investment securities are exposed to various risks, including interest rate, credit and overall market volatility. As a result of these risks, it is reasonably probable that the market values of investment securities could increase or decrease in the near term, resulting in a material impact on the value of our pension assets. Increases or decreases in the market values could materially affect the current value of the trusts and the future level of pension and

other postretirement benefit expense. The current conditions in the credit market could negatively impact the assets in our trusts, but at this time we still believe that the 8.75 percent rate and the 6.85 percent rate for respective Pension and PBOP Plan assets are appropriate long-term rate of return assumptions.

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

We calculate the expected return on plan assets by applying our assumed rate of return to a four-year rolling average of plan asset fair values, which reduces year-to-year volatility. This calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the calculated expected return and the actual return based on the change in the fair value of assets during the year. At December 31, 2008, total investment losses to be reflected in the four-year rolling average of plan assets over the next four years were $672.3 million and $73.9 million**,** for the Pension Plan and the PBOP Plan, respectively. As these asset losses are reflected in the average plan asset fair values, they will be subject to amortization with other unrecognized gains/losses. The Plans currently amortize unrecognized gains/losses as a component of pension and PBOP expense over approximately 12 years, which were the average future service period of the employees at December 31, 2008.

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

Discount Rate: The discount rate that is utilized in determining future pension and PBOP obligations is based on a yield-curve approach where each cash flow related to the Pension Plan or PBOP Plan liability stream is discounted at an interest rate specifically applicable to the timing of the cash flow. The yield curve is developed from the top quartile of AA rated Moody s and S&P s bonds without callable features outstanding at December 31, 2008. This process calculates the present values of these cash flows and calculates the equivalent single discount rate that produces the same present value for future cash flows. The discount rates determined on this basis are 6.89 percent for the Pension Plan and 6.90 percent for the PBOP Plan at December 31, 2008. Discount rates used at December 31, 2007 were 6.60 percent for the Pension Plan and 6.35 percent for the PBOP Plan.

Forecasted Expenses and Expected Contributions: Due to the effect of the unrecognized actuarial gains/losses and based on the long-term rate of return assumptions and discount rates as noted above as well as various other assumptions, we estimate that expected forecasted expense for the Pension Plan and PBOP Plan will be $40.3 million and $37.3 million, respectively, in 2009, which is included in our guidance.

Future actual Pension and PBOP expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the plans and amounts capitalized. We expect to continue with our policy to contribute to the PBOP Plan at the amount of PBOP expense, excluding curtailments and special benefit amounts. Beginning in 2007, we made additional contributions to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amounted to $3.7 million in 2008 and is estimated to be $3.4 million in 2009.

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

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

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

	At December 31,							
	Pension Plan Cost				Postretirement Plan Cost			
Assumption Change		**2008**		**2007**		**2008**		**2007**
Lower long-term rate of return	$	11.8	$	11.1	$	1.3	$	1.1
Lower discount rate	$	11.6	$	12.9	$	1.4	$	1.4
Lower compensation increase	$	(6.2)	$	(6.9)		N/A		N/A

Plan Assets: The fair value of the Pension Plan assets decreased by $902.6 million to $1.56 billion at December 31, 2008. This decrease includes benefit payments of $127.6 million in 2008. The Projected Benefit Obligation (PBO) for the Pension Plan increased by $40.8 million to $2.3 billion at December 31, 2008. These changes have changed the funded status of the Pension Plan on a PBO

basis from an overfunded position of $202.5 million at December 31, 2007 to an underfunded position of $740.9 million at December 31, 2008. The PBO includes expectations of future employee compensation increases.

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

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

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

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

Goodwill and Intangible Assets: SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill balances be reviewed for impairment at least annually by applying a fair value-based test. The testing of goodwill for impairment requires us to use estimates and judgment. We have selected October 1st of each year as the annual goodwill impairment testing date. Management reviews triggering events as defined under SFAS No. 142 throughout the year and has determined that no triggering events occurred in 2008 that would have required interim testing before or after October 1st. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount of the goodwill. If goodwill is deemed to be impaired, it is written off in the current period to the extent it is impaired.

We completed our impairment analysis as of October 1, 2008 for the Yankee Gas goodwill balance of $287.6 million and determined that no impairment exists. In performing the required impairment evaluation, we estimated the fair value of the Yankee Gas reporting unit and compared it to the carrying amount of the reporting unit, including goodwill. We estimated the fair value of Yankee Gas using discounted cash flow methodologies and an analysis of comparable companies or transactions. We review the outcome of each of the approaches annually and weight them appropriately to determine the fair value of Yankee Gas. This analysis requires the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, and long-term earnings and merger multiples of comparable companies.

We determined the discount rate using the capital asset pricing model methodology. This methodology uses a weighted average cost of capital in which the ROE is calculated using risk-free rates, stock premiums and a beta representing Yankee Gas' volatility relative to the overall market. The discount rate fluctuates from year to year as it is based on external market conditions. In 2008, the discount rate decreased because the risk-free rate and the beta were much lower in 2008 than in 2007 due to the current market conditions and the stability of the natural gas industry in this market. All of these assumptions are critical to the estimate and can change from period to period.

Updates to these assumptions in future periods, particularly changes in discount rates, could result in future impairments of goodwill. Although our evaluations since adopting SFAS No. 142 have not resulted in impairment, the estimated fair value of Yankee Gas is sensitive to changes in assumptions. For example, if the risk adjusted discount rate increased from approximately 5.95 percent to approximately 6.52 percent or the merger multiple of comparable companies decreased from approximately 10.5 to approximately 9.7 and the weighting of our valuation methodologies remained the same, then the estimated fair value of Yankee Gas would be lower than its carrying value.

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

Part of the annual process in making adjustments to these estimates, as needed, is a reconciliation of the actual tax positions and amounts included on our income tax returns as filed in the fall of each year for the previous tax year to the estimates or provisions made during the income tax estimation process described above. In the third quarter of 2008, the impact of these return to provision adjustments on income tax expense was benefits of $3.2 million and $1 million for NU and CL&P, respectively.

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

Effective on January 1, 2007, we implemented Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." FIN 48 applies to all income tax positions previously filed in a tax return and income tax positions expected to be taken in a future tax return that have been reflected on our balance sheets. FIN 48 addresses the methodology to be used prospectively in recognizing, measuring and classifying the amounts associated with tax positions that are deemed to be uncertain, including related interest and penalties.

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

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

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

The fair value of derivatives is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the company determines whether it is a derivative by using amounts referenced in default provisions and other relevant sections of the contract. The estimated quantities to be served are updated during the term of the contract, and such updates can have a material impact on mark-to-market amounts. The fair value of derivative assets and liabilities with the same counterparty are offset as permitted under FIN 39, "Offsetting of Amounts Related to Certain Contracts - an Interpretation of APB Opinion No. 10 and FASB Statement No. 105." The actual experience on our derivative contracts as they are settled has not resulted in a material impact on earnings. For the year ended December 31, 2008, the realized gains on the wholesale derivative contracts of Select Energy at settlement date were $3 million ($5 million pre-tax).

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

In 2007, CL&P entered into CfDs with owners of plants to be built or modified. The CfDs are derivatives that are required to be marked to market on the balance sheet. However, due to the significance of the non-observable capacity prices associated with modeling the fair values of these contracts, their initial fair values were not recorded in CL&P s financial statements pursuant to EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." This guidance applies to initial fair values only, and not to subsequent changes in value. Subsequent changes in the values of these contracts were substantial, primarily due to reductions in the expected market prices of capacity. The value of CfDs at December 31, 2008 included approximately $100 million of initial gains and losses, previously deferred due to the use of significant unobservable inputs in the valuation that were recorded upon adoption of SFAS No. 157 on January 1, 2008. The changes in CfD values since inception were recorded as a regulatory asset as the costs of the contracts are recoverable from CL&P s customers. Significant judgment was involved in estimating the fair values of the contracts, including projections of capacity prices and reflecting the probabilities of cash flows considering the risks and uncertainties associated with the contracts.

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

For further information, see Note 1E, "Summary of Significant Accounting Policies - Derivative Accounting," and Note 3, "Derivative Instruments," to the consolidated financial statements.

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

Unbilled revenues represent an estimate of electricity or gas delivered to customers for which the customers have not yet been billed. Unbilled revenues are included in revenue on the statement of income and are assets on the balance sheet that are reclassified to accounts receivable in the following month as customers are billed. Such estimates are subject to adjustment when actual meter readings become available, when changes in estimating methodology occur and under other circumstances. There were no changes in estimating methodology in 2008.

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

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

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

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

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

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

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

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

The Energy Independence Act required the DPUC to consider the impact on distribution companies of entering into long-term contracts for capacity and contracts to purchase renewable energy products from new generating plants. We reviewed each contract to determine the appropriate accounting treatment based on the terms of the contracts, which included variable and fixed pricing elements. In 2007, CL&P entered into a 15-year agreement beginning in 2010 to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. We determined that this contract was a variable interest in a VIE. In 2008, CL&P and UI entered into seven additional long-term agreements with proposed renewable energy plants, of which four were determined to

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

In 2007, CL&P entered into two Capacity CfDs associated with the capacity of two generating projects to be built or modified, and UI entered into two capacity-related CfDs, one with a generating project to be built and one with a new demand response project. The contracts, referred to as Capacity CfDs, obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. As directed by the DPUC, CL&P has a cost sharing agreement with UI under which it will share the costs and benefits of these four Capacity CfDs with 80 percent to CL&P and 20 percent to UI. We determined that the Capacity CfDs and the related cost sharing agreement are derivatives and that the projects do not require consolidation. Quantitative modeling was not required for these contracts because we concluded that the derivative contracts are not variable interests in the projects.

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

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

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

Other Matters

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

Accounting Standards Issued But Not Yet Adopted:

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," which is effective January 1, 2009. SFAS No. 160 requires ownership interests in subsidiaries held by third parties (noncontrolling interests) to be

presented within equity and clearly identified and labeled. It sets forth requirements for income statement presentation related to the activities of noncontrolling interests and for accounting for changes in ownership interests and provides guidance for deconsolidation. Implementation of SFAS No. 160 is not expected to have a material impact on our consolidated financial statements or the consolidated financial statements of CL&P, PSNH or WMECO.

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

SFAS No. 157, which establishes a framework for identifying and measuring fair value, was issued in 2006 and applied in 2008 to the fair value measurements of financial assets and liabilities of NU and its subsidiaries. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 is required to be applied to nonrecurring fair value measurements of non-financial assets and liabilities beginning in 2009, including asset retirement obligations (ARO) and goodwill and other impairment analyses. Implementation of SFAS No. 157 to non-financial assets and liabilities is not expected to have a material impact on our consolidated financial statements or the consolidated financial statements of CL&P, PSNH or WMECO.

Contractual Obligations and Commercial Commitments:

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

NU *(Millions of Dollars)*	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Totals**
Long-term debt maturities [(a)] [(b)]	$ 54.3	$ 4.3	$ 4.3	$ 267.3	$ 305.0	$ 3,207.8	$ 3,843.0
Estimated interest payments on existing debt [(c)]	222.7	219.2	218.9	210.1	194.4	2,114.8	3,180.1
Capital leases [(d)]	2.4	2.4	2.5	2.6	2.4	15.5	27.8

Operating leases (e)	24.6	18.9	7.1	6.1	5.9	23.9	86.5
Required funding of pension obligations (e) (f)	-	150.0	-	-	-	-	150.0
Required funding of other postretirement benefit obligations (e)	37.3	38.7	40.9	42.8	29.3	N/A	189.0
Estimated future annual regulated company costs (g)	791.6	723.9	779.7	715.0	523.6	2,855.2	6,389.0
Estimated future annual NU Enterprises costs (g)	40.3	41.9	42.9	38.8	44.7	-	208.6
Other purchase commitments (e) (h)	3,162.3	-	-	-	-	-	3,162.3
Totals (i) (j)	$ 4,335.5	$ 1,199.3	$ 1,096.3	$ 1,282.7	$ 1,105.3	$ 8,217.2	$ 17,236.3

CL&P

(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Totals**
Long-term debt maturities (a) (b)	$ -	$ -	$ -	$ -	$ -	$ 2,031.7	$ 2,031.7
Estimated interest payments on existing debt (c)	119.2	119.2	119.2	119.2	119.2	1,548.8	2,144.8
Capital leases (d)	1.9	1.9	1.9	2.0	1.9	14.9	24.5
Operating leases (e)	14.4	12.5	3.9	3.4	3.3	19.7	57.2
Required funding of other postretirement benefit obligations (e)	15.5	15.9	16.6	17.4	10.6	N/A	76.0
Estimated future annual costs (g)	367.9	400.9	512.6	533.7	442.0	2,478.5	4,735.6
Other purchase commitments (e) (h)	573.4	-	-	-	-	-	573.4
Totals (i) (j)	$ 1,092.3	$ 550.4	$ 654.2	$ 675.7	$ 577.0	$ 6,093.6	$ 9,643.2

(a)

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

(b)

Long-term debt maturities exclude $298.6 million and $243 million for NU and CL&P, respectively, of fees and interest due for spent nuclear fuel disposal costs, a positive $20.8 million for NU of net changes in fair value and a negative $4.9 million and $4.3 million for NU and CL&P, respectively, of net unamortized premium and discount as of December 31, 2008.

(c)

Estimated interest payments on fixed-rate debt are calculated by multiplying the coupon rate on the debt by its scheduled notional amount outstanding for the period of measurement. Estimated interest payments on floating-rate debt are calculated by multiplying the average of the 2008 floating-rate resets on the debt by its scheduled notional amount outstanding for the period of measurement. This same rate is then assumed for the remaining life of the debt. Interest payments on debt that have an interest rate swap in place are estimated using the effective cost of debt resulting from the swap rather than the underlying interest cost on the debt, subject to the fixed and floating methodologies.

(d)

The capital lease obligations include imputed interest of $14.4 million and $13.3 million for NU and CL&P, respectively, as of December 31, 2008.

(e)

Amounts are not included on our consolidated balance sheets.

(f)

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

(g)

Other than the net mark-to-market changes on respective derivative contracts held by both the regulated companies and NU Enterprises, these obligations are not included on our consolidated balance sheets. For further information on these estimated future annual costs, see Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the consolidated financial statements.

(h)

Excludes FIN 48 unrecognized tax benefits of $156.3 million for NU and $106.4 million for CL&P as of December 31, 2008, as we cannot make reasonable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities.

(i)

Amount represents open purchase orders, excluding those obligations that are included in the capital leases, operating leases, estimated future annual regulated company costs and the estimated future annual NU Enterprises costs. These payments are subject to change as certain purchase orders include estimates based on projected quantities of material and/or services that are provided on demand, the timing of which cannot be determined. Because payment timing cannot be determined, we include all open purchase order amounts in 2009.

(j)

For NU, excludes other long-term liabilities, including a significant portion of the FIN 48 unrecognized tax benefits described above, environmental reserves ($26.8 million), various injuries and damages reserves ($35.4 million), employee medical insurance reserves ($6.6 million), long-term disability insurance reserves ($12 million) and the ARO liability reserves ($50.6 million) as we cannot make reasonable estimates of the periods. For CL&P, excludes FIN 48 unrecognized tax benefits, described above, environmental reserves ($2.8 million), various injuries and damages reserves ($24.2 million), employee medical insurance reserves ($2 million), long-term disability insurance reserves ($3.6 million) and the ARO liability reserves ($28.7 million).

RRB amounts are non-recourse to us, have no required payments over the next five years and are not included in this table. The regulated companies' standard offer service contracts and default service contracts also are not included in this table. The estimated payments under interest rate swap agreements are not included in this table as the estimated payment amounts are not determinable. For further information regarding our contractual obligations and commercial commitments, see the consolidated statements of capitalization and Note 2, "Short-Term Debt," Note 5A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," Note 10, "Leases," and Note 11, "Long-Term Debt," to the consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, future financial performance or growth or other statements that are not historical facts. These statements are "forward looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify these "forward looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward looking statements involve risks and uncertainties that may cause actual results or outcomes to differ materially from those included in the forward looking statements. Factors that may cause actual results to differ materially from those included in the forward looking statements include, but are not limited to, actions or inactions by local, state and federal regulatory bodies; changes in business and economic conditions, including their impact on interest rates, bad debt expense and demand for our products and services; changes in weather patterns; changes in laws, regulations or regulatory policy; changes in levels and timing of capital expenditures; disruptions in the capital markets or events that make our access to necessary capital more difficult or costly; developments in legal or public policy doctrines; technological developments; changes in accounting standards and financial reporting regulations; fluctuations in the value of our remaining competitive electricity positions; actions of rating agencies; and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports to the Securities and Exchange Commission. We undertake no obligation to update the information contained in any forward looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events.

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

RESULTS OF OPERATIONS - NU CONSOLIDATED

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

Income Statement Variances	**2008 over/(under) 2007**		**2007 over/(under) 2006**	
	Amount	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (22)	- %	$ (1,055)	(15) %
Operating Expenses:				
Fuel, purchased and net interchange power	(354)	(11)	(1,280)	(28)
Other operation	60	6	(160)	(14)
Maintenance	43	20	18	9
Depreciation	13	5	25	10
Amortization of regulatory assets, net	146	(a)	24	(a)
Amortization of rate reduction bonds	4	2	13	7
Taxes other than income taxes	15	6	1	1
Total operating expenses	(73)	(1)	(1,359)	(20)
Operating income	51	10	304	(a)
Interest expense, net	29	12	2	1
Other income, net	(11)	(18)	(3)	(4)
Income from continuing operations before income tax expense	11	3	299	(a)
Income tax expense/(benefit)	(4)	(3)	186	(a)
Preferred dividends of subsidiary	-	-	-	-
Income from continuing operations	15	6	113	85
Income/(loss) from discontinued operations	(1)	(100)	(337)	(100)
Net income/(loss)	$ 14	6 %	$ (224)	(48) %

(a) Percent greater than 100.

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

Comparison of 2008 to 2007

Operating Revenues

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

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

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

Electric distribution revenues decreased $213 million primarily due to the portion of revenues that does not impact earnings ($281 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations of transmission segment intracompany billings to the distribution segment, partially offset by the component of revenues that flows through to earnings ($68 million). The portion of the electric distribution segment revenues that flows through to earnings increased $68 million primarily due to increases in retail rates at each of the regulated companies ($89 million), partially offset by lower retail

electric sales ($16 million). Retail electric sales decreased 3.5 percent in 2008 compared with 2007. Gas distribution revenues increased $63 million primarily due to increased recovery of higher gas costs, the rate increase effective July 1, 2007 and higher firm gas sales. Firm gas sales increased 2.1 percent in 2008 compared with 2007.

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

Fuel, Purchased and Net Interchange Power

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

Other Operation

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

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

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

Maintenance

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

Depreciation

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

Amortization of Regulatory Assets, Net

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

Amortization of Rate Reduction Bonds

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

Taxes Other than Income Taxes

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

Interest Expense, Net

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

Other Income, Net

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

Income Tax Expense

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

<u>Comparison of 2007 to 2006</u>

Operating Revenues

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

NU consolidated	$	5,822	$	6,877	$	(1,055)

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

Operating Revenues

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

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

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

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

Fuel, Purchased and Net Interchange Power

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

Other Operation

Other operation expenses decreased $160 million in 2007 primarily due to lower NU Enterprises expenses ($115 million) and lower regulated companies distribution and transmission segment expenses ($49 million).

NU Enterprises' expenses decreased $115 million primarily due to the exit from components of the competitive businesses during the latter part of 2006 and the $25 million donation to the NU Foundation in 2006.

Lower regulated company distribution and transmission segment expenses of $49 million are primarily due to lower reliability must run (RMR) expenses at CL&P ($133 million), partially offset by higher Energy Independence Act (EIA) expenses that are tracked and recovered through the regulatory tracking mechanisms ($29 million), higher administration and general expenses at CL&P, WMECO and PSNH ($22 million), higher retail transmission expenses at PSNH and WMECO ($21 million) and Summer Savings Rewards Program that was implemented in 2007 at CL&P as a result of a legislative act ($14 million).

Maintenance

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

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

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

Depreciation

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

Amortization

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

Amortization of Rate Reduction Bonds

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

Interest Expense, Net

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

Other Income, Net

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

Income Tax (Benefit)/Expense

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

Income/(Loss) from Discontinued Operations

See Note 15, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements for a description and explanation of the discontinued operations.

RESULTS OF OPERATIONS - THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

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

Income Statement Variances	**2008 over/(under) 2007**		**2007 over/(under) 2006**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (123)	(3) %	$ (298)	(7) %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(432)	(19)	(327)	(13)
Other operation	22	4	(79)	(13)
Maintenance	22	21	7	6
Depreciation	11	7	4	3
Amortization of regulatory assets/(liabilities), net	144	(a)	32	(a)
Amortization of rate reduction bonds	10	7	9	7
Taxes other than income taxes	11	7	7	4
Total operating expenses	(212)	(6)	(347)	(9)
Operating Income	89	31	49	21
Interest expense, net	8	6	21	17
Other income, net	2	5	2	5
Income before income tax expense	83	45	30	19
Income tax expense	25	49	96	(a)
Net income	$ 58	43 %	$ (66)	(33) %

(a) Percent greater than 100.

<u>Comparison of the Year 2008 to the Year 2007</u>

Operating Revenues

Operating revenues decreased $123 million due to lower distribution segment revenues ($233 million), partially offset by higher transmission segment revenues ($110 million).

The distribution segment revenues decreased $233 million primarily due to the component of revenues that does not impact earnings ($296 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations, partially offset by the component of revenues that flows through to earnings, which increased $62 million.

The $296 million distribution segment revenue decrease that does not impact earnings is primarily due to the components of retail revenues that are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs ($217 million) and consolidation eliminations of transmission segment intracompany billings to the distribution segment ($78 million). The distribution revenue included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs decreased $217 million primarily due to a decrease in revenues associated with the recovery of GSC and related FMCC ($314 million) and delivery related FMCC ($75 million), partially offset by higher retail transmission revenues ($65 million) mainly as a result of higher 2008 rates, higher wholesale revenues ($59 million), and higher SBC revenues ($36 million). The lower GSC and related FMCC revenue was primarily due to a reduction in load, caused primarily by customer migration to third party suppliers, lower congestion costs and lower sales in 2008. The lower delivery-related FMCC revenue was primarily due to a decrease in this rate component in 2008 as a result of lower RMR, VAR support and southwest Connecticut energy resource costs in 2008, as well as a larger prior year overrecovery being refunded to customers in 2008 as compared to 2007. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The portion of the distribution segment revenues that flows through to earnings increased $62 million primarily due to the rate increase effective February 1, 2008 ($75 million), partially offset by lower retail sales ($10 million). Retail sales decreased 3.7 percent in 2008 compared to 2007.

Transmission segment revenues increased $110 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $432 million primarily due to a decrease in GSC supply costs ($231 million), a decrease in deferred fuel costs ($174 million) and lower other purchased power costs ($27 million), all of which are included in DPUC approved tracking mechanisms. The $231 million decrease in GSC supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers and lower retail sales. These GSC supply costs are the contractual amounts CL&P must pay to various suppliers that have earned the right to supply SS and LRS load through a competitive solicitation process. The $174 million decrease in deferred fuel costs was primarily due to the combined effect of CL&P having a supply and delivery-related net FMCC overrecovery in 2007 and a supply and delivery-related net FMCC underrecovery in 2008.

Other Operation

Other operation expenses increased $22 million primarily due to higher costs that are tracked and recovered through distribution tracking mechanisms ($104 million) such as retail transmission ($59 million), RMR ($17 million), higher uncollectibles ($12 million), higher tracked administrative and general expenses ($9 million), and higher EIA expenses ($6 million). In addition, there were higher transmission segment expenses ($5 million), partially offset by consolidation eliminations of transmission segment intracompany billing to the distribution segment ($80 million) and lower distribution segment expenses ($8 million) primarily due to lower pension, regulatory assessments and workers compensation expenses, partially offset by a charge to refund the 2004 procurement incentive fee that was recognized in 2005 earnings.

Maintenance

Maintenance expenses increased $22 million in 2008 primarily due to higher distribution overhead lines ($10 million), primarily due to more storms in 2008 compared to 2007, higher tree trimming expenses ($6 million), higher transmission segment expenses ($4 million) and higher distribution substation equipment ($2 million).

Depreciation

Depreciation expense increased $11 million primarily due to higher utility plant balances resulting from completed construction programs put into service.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net increased $144 million primarily due to higher amortization related to the recovery of transition charges ($62 million), a higher recovery and lower expenses for SBC ($50 million) and a credit in 2007 pertaining to the refund of the GSC overrecovery ($29 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs increased $10 million. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $11 million primarily due to higher gross earnings taxes as a result of higher distribution revenues that are subject to gross earnings tax ($13 million) and higher property taxes as a result of higher plant balances and higher municipal tax rates ($2 million), partially offset by lower payroll taxes charged to expense ($3 million).

Interest Expense, Net

Interest expense, net increased $8 million primarily due to higher long-term debt interest ($21 million) resulting from the $200 million debt issuance in September 2007, the $300 million debt issuance in March 2007 and the $300 million debt issuance in May 2008, partially offset by lower RRB interest resulting from lower principal balances outstanding ($9 million) and lower other interest ($3 million) mostly related to short-term debt.

Other Income, Net

Other income, net increased $2 million primarily due to a higher AFUDC equity income ($9 million) as a result of higher eligible CWIP due to the transmission construction program, higher interest income related to the 2008 federal tax settlement ($6 million) and higher EIA incentives ($2 million), partially offset by higher investment losses ($10 million) primarily due to the supplemental benefit trust, a decrease in conservation and load management incentive income ($3 million) and a decrease in investment income ($2 million).

Income Tax Expense

Income tax expense increased $25 million primarily due to higher pre-tax earnings being subject to tax at marginal rates, partially offset by flow through impacts associated with plant differences and bad debts, thereby reducing the effective tax rate.

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 overrecoveries 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 overcollections refunded to customers or undercollections collected from customers in future periods.

The distribution component of revenues that 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 remitted RMR payments that must be returned to customers.

Other Operation

Other operation expenses decreased $79 million primarily due to lower RMR costs ($133 million) that are tracked and recovered through the FMCC, partially offset by higher Energy Independence Act (EIA) expenses that will also be recovered through the FMCC deferral mechanism ($29 million), Summer Saver Rewards Program that 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 expense.

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 RRBs increased $9 million. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

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 RRB 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 CWIP due to the transmission construction program, higher EIA incentives ($4 million) and higher equity of earnings of regional nuclear generating companies ($3 million), partially offset by the elimination of the Transitional Standard Offer (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

Income tax expense increased $96 million primarily due to the nonrecurring tax items in 2006 that 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.

LIQUIDITY

While the impact of continued market volatility and the extent and impacts of any economic downturn cannot be predicted, we currently believe that CL&P has sufficient operating flexibility and access to funding sources to maintain adequate amounts of liquidity (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). The credit outlooks for CL&P are all stable, with all its ratings and outlooks affirmed by S&P in late October 2008. CL&P has modest risk of calls for collateral due to its business model, as described under "Liquidity-Impact of Financial Market Conditions" in this "Management s Discussion and Analysis of Financial Condition and Results of Operations." Capital contributions from NU parent and other internal sources of funding are provided to CL&P as necessary. CL&P does not have any long-term debt maturing in 2009, and projected capital expenditures for 2009 are significantly less than 2008.

CL&P had consolidated operating cash flows of $267.3 million in 2008, after RRB payments included in financing activities, compared with operating cash flows of $4.5 million in 2007 and $138.8 million in 2006, both after RRB payments. Operating cash flows in 2007 include tax payments of approximately $177.2 million related to the 2006 sale of NU's competitive generation business. Other drivers resulting in increased operating cash flows in 2008 were higher operating results after adjustments for reconciling items to net income primarily related to the significant increase in transmission segment earnings and a $77.8 million annualized increase in distribution rates, effective February 1, 2008. The increase in operating cash flows was also due to an income tax net settlement of approximately $33 million in the fourth quarter of 2008 and the cash flow benefit of our accounts payable balances having increased by $25 million. These factors were partially offset by a net reduction in other working capital items resulting primarily from a net $141 million increase in the cash flow benefit of our accounts receivable and unbilled revenue balances, which also included investments in securitizable assets.

CL&P projects consolidated operating cash flows of approximately $365 million in 2009, after approximately $183 million of RRB payments. This projection represents an increase of approximately $100 million from 2008 operating cash flows, after RRB payments, which is primarily due to the reflection in 2009 rates of CL&P s major southwest Connecticut transmission projects completed in 2008; a $20.1 million annualized increase in distribution rates, effective February 1, 2009; and the recovery in 2009 of certain regulatory underrecoveries as of December 31, 2008, including $31.9 million from its semi-annual FMCC filing in February 2009 as compared to a $105 million overrecovery at December 31, 2007.

On February 13, 2009, CL&P issued $250 million of first and refunding mortgage bonds due February 1, 2019 and carrying a coupon of 5.5 percent. Proceeds from this issuance will be used to repay short-term debt and fund CL&P's capital investment program, which is projected to be approximately $400 million in 2009. In mid-2009 or earlier depending on market opportunities, NU expects to issue between $250 million and $300 million of equity, a portion of which will be used to fund CL&P s 2009 capital investment program. This program will also be funded by available short-term borrowings and the projected growth in 2009 operating cash flows described above.

As of December 31, 2008 and February 25, 2009, CL&P had borrowings of $188 million under the $400 million credit facility it shares with other NU subsidiaries, of which it can borrow up to $200 million. Other financing activities for 2008 included a $300 million issuance of 10-year bonds in May 2008 and capital contributions from NU parent of $210 million, offset by $106.5 million in common dividends paid to NU parent.

On June 30, 2008, due to the availability and lower relative cost of other liquidity sources, CL&P chose to terminate the arrangement under which CL&P could sell to a financial institution up to $100 million of accounts receivable and unbilled revenues.

Cash capital expenditures included on the accompanying consolidated statements of cash flows do not include amounts incurred on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. CL&P s cash capital expenditures totaled $849.5 million in 2008, compared with $826.2 million in 2007. This increase was primarily the result of higher distribution segment capital expenditures in 2008.

RESULTS OF OPERATIONS - PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

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

Income Statement Variances	**2008 over/(under) 2007**		**2007 over/(under) 2006**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ 58	5 %	$ (58)	(5) %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	28	5	(58)	(10)
Other operation	7	3	30	17
Maintenance	17	23	3	4
Depreciation	3	6	4	7
Amortization of regulatory assets, net	2	24	(46)	(86)
Amortization of rate reduction bonds	(7)	(13)	3	6
Taxes other than income taxes	2	7	2	5
Total operating expenses	52	5	(62)	(6)
Operating Income	6	5	4	3
Interest expense, net	4	8	-	-
Other income, net	1	9	(1)	(9)
Income before income tax expense	3	4	3	4
Income tax expense	(1)	(4)	(16)	(42)
Net income	$ 4	7 %	$ 19	54 %

<u>Comparison of the Year 2008 to the Year 2007</u>

Operating Revenues

Operating revenues increased $58 million in 2008 due to higher distribution segment revenues ($46 million) and higher transmission segment revenues ($12 million).

The distribution segment revenues increased $46 million primarily due to the portion of revenues that does not impact earnings ($37 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations of transmission segment intracompany billings to the distribution segment, and the component of revenues that flows through to earnings ($8 million). The portion of distribution segment revenues that flows through to earnings increased $8 million primarily as a result of rate changes ($13 million) from increases effective July 1, 2007 and January 1, 2008, partially offset by a rate decrease effective July 1, 2008. The combined increase in rates is partially offset by lower retail sales ($4 million). Retail sales decreased 2.5 percent in 2008 compared to the same period in 2007.

The $37 million distribution from revenue increase that does not impact earnings is due to the components of retail revenues that are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs ($55 million), partially offset by revenues that are eliminated in consolidation ($18 million). The distribution revenue included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs increased $55 million primarily due to the pass-through of higher energy supply costs ($78 million), higher retail transmission revenues ($17 million), higher wholesale revenues ($8 million), and higher Northern Wood Power Plant renewable energy certificate revenues ($3 million), partially offset by a decrease in the SCRC ($55 million) primarily due to a decrease in the SCRC rate effective July 1, 2008. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased $12 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs increased $28 million primarily due to higher forward energy market prices, partially offset by a decrease in payments to higher priced IPPs in 2008 as contracts expired.

Other Operation

Other operation expenses increased $7 million primarily due to higher costs that are tracked and recovered through distribution tracking mechanisms ($13 million) primarily due to retail transmission. In addition, there were higher distribution segment expenses ($10 million) primarily due to higher customer account and storm restoration expenses, and higher transmission segment expenses ($2 million), partially offset by consolidation eliminations of transmission segment intracompany billings to the distribution segment ($18 million).

Maintenance

Maintenance expenses increased $17 million primarily due to higher generation segment expenses that are tracked and recovered through an NHPUC approved tracking mechanism ($15 million) primarily as a result of the Merrimack Station maintenance outages

with the remainder of the increase primarily due to higher distribution segment expenses related to storms and the Reliability Enhancement Program (REP) that began on July 1, 2007.

Depreciation

Depreciation expense increased $3 million primarily due to higher utility plant balances resulting from completed construction programs put into service.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net increased $2 million primarily as a result of increased recoveries of previously deferred storm costs.

Amortization of Rate Reduction Bonds

Amortization of RRBs decreased $7 million primarily due to the retirement of $50 million of RRBs in the first quarter of 2008.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $2 million primarily due to higher property taxes ($3 million) as a result of higher net plant balances and higher local municipal tax rates, partially offset by lower payroll taxes ($1 million).

Interest Expense, Net

Interest expense, net increased $4 million primarily due to higher long-term debt interest ($7 million) resulting primarily from the $70 million debt issuance in September 2007 and the $110 million debt issuance in May 2008, partially offset by lower RRB interest resulting from lower principal balances outstanding ($2 million).

Other Income, Net

Other income, net increased $1 million primarily due to higher AFUDC equity income as a result of a higher eligible CWIP and lower short-term debt resulting in an increase in CWIP financed by equity ($2 million) and higher interest income related to the 2008 federal tax settlement ($2 million), partially offset by higher investment losses ($2 million) primarily due to the supplement benefit trust and lower investment income ($1 million).

Income Tax Expense

Income tax expense decreased $1 million primarily due to lower plant related flow through impacts, partially offset by higher pre-tax earnings.

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 that are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($87 million), partially offset by an increase of the distribution component of PSNH's retail revenues that 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 SBC revenue ($4 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 PSNH s retail revenues that 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 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 RRBs increased $3 million. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

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.

LIQUIDITY

PSNH had consolidated operating cash flows of $116.4 million in 2008, after RRB payments included in financing activities, compared with operating cash flows of $95.5 million in 2007 and $125 million in 2006, both after RRB payments. The increase in 2008 operating cash flows was primarily due to a $25 million decrease in net income tax payments, and an increase in cash flow benefits of our accounts payable balances of $50.1 million excluding approximately $50 million in unpaid major storm costs that are deferred and expected to be recovered from customers or insurance proceeds, offset by a $42.1 million increase in generation fuel costs and supplies primarily related to higher prices and other miscellaneous negative cash flow impacts.

We expect the 2009 consolidated operating cash flows of PSNH after RRB payments to be negatively impacted in the first half of the year by the payment of major storm costs incurred in December 2008. However, operating cash flows in the second half of the year should strengthen as these costs begin to be recovered from customers.

RESULTS OF OPERATIONS - WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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

Income Statement Variances	**2008 over/(under) 2007**		**2007 over/(under) 2006**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (23)	(5) %	$ 33	8 %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	1	-	(44)	(16)
Other operation	(22)	(22)	17	21
Maintenance	2	11	3	18
Depreciation	-	-	4	21
Amortization of regulatory assets/(liabilities), net	2	17	38	(a)
Amortization of rate reduction bonds	1	7	1	7
Taxes other than income taxes	-	-	-	-
Total operating expenses	(16)	(4)	19	5
Operating Income	(7)	(14)	14	35
Interest expense, net	-	-	1	5
Other income, net	(2)	(50)	2	66
Income before income tax expense	(9)	(24)	15	63
Income tax expense	(4)	(28)	7	88
Net income	$ (5)	(22) %	$ 8	51 %

(a) Percent greater than 100.

<u>Comparison of the Year 2008 to the Year 2007</u>

Operating Revenues

Operating revenues decreased $23 million in 2008 due to lower distribution segment revenues ($26 million), partially offset by higher transmission segment revenues ($3 million).

The distribution segment revenues decreased $26 million primarily due to the portion of revenues that does not impact earnings ($24 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations of transmission segment intracompany billings to the distribution segment, and the component of revenues that flows through to earnings ($2 million). The $24 million distribution segment revenue decrease that does not impact earnings is due to the components of retail revenues that are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs ($18 million) and revenues that are eliminated in consolidation ($6 million). The distribution revenue DPU approved tracking mechanisms that track the recovery of certain incurred costs decreased $18 million primarily due to lower retail transmission revenues ($12 million) and lower pension tracker and default service true-up revenues ($8 million). Tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The portion of the distribution segment revenues that flows through to earnings decreased $2 million primarily due to lower retail sales ($2 million) and a service quality performance assessment charge ($1 million), partially offset by the rate increase effective January 1, 2008 ($2 million). Retail sales decreased 4.2 percent in 2008 compared to the same period in 2007.

Transmission segment revenues increased $3 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $1 million primarily due to higher basic service supply costs, partially offset by an increased deferral of excess basic service expense over basic service revenue and lower amortization of the CT Yankee regulatory asset. The basic service supply costs are the contractual amounts we must pay to various suppliers that serve basic service load after winning a competitive solicitation process. To the extent these costs do not match the revenues collected from customers, the DPU allows the difference to be deferred for future collection or refund.

Other Operation

Other operation expenses decreased $22 million primarily due to lower costs that are tracked and recovered through distribution tracking mechanisms ($20 million) such as retail transmission ($11 million) and lower tracked administrative and general expenses mainly due to pension expense ($9 million). In addition, consolidation eliminations of transmission segment intracompany billings to the distribution segment reduced expenses ($6 million), partially offset by higher distribution segment expenses ($2 million) primarily due to higher uncollectible expenses and higher transmission segment expenses ($1 million).

Maintenance

Maintenance expenses increased $2 million primarily due to higher tree trimming expenses as a result of storms.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $2 million primarily due to the deferral of transition revenues collected in excess of allowed transition costs resulting mainly from higher power contract market values.

Amortization of Rate Reduction Bonds

Amortization of RRBs increased $1 million. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

Other Income, Net

Other income, net decreased $2 million in 2008 primarily due to higher investment losses ($2 million) primarily due to the supplemental benefit trust and lower investment income ($2 million), partially offset by higher interest income related to the 2008 federal tax settlement ($1 million) and higher AFUDC equity income as a result of a higher eligible CWIP and lower short-term debt resulting in an increase in CWIP financed by equity ($1 million).

Income Tax Expense/(Benefit)

Income tax expense decreased $4 million primarily due to lower pre-tax earnings.

<u>Comparison of the Year 2007 to the Year 2006</u>

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 that 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 from customers in future periods.

The distribution component of revenues that 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 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 RRBs increased $1 million. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

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 RRB 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.

LIQUIDITY

WMECO had consolidated operating cash flows of $53.9 million in 2008, after RRB payments included in financing activities, compared with operating cash flows of $24.9 million in 2007 and $4.4 million in 2006, both after RRB payments. The improvement in 2008 operating cash flows was primarily due to a $71.5 million decrease in net income tax payments that were absent the payment of $47.9 million in federal and state income taxes in the first quarter of 2007 as a result of the 2006 sale of NU s competitive generation business. This factor was partially offset by a decrease in regulatory overrecoveries of approximately $49 million.

We expect the 2009 consolidated operating cash flows of WMECO after RRB payments to be negatively impacted by the payment of major storm costs incurred in December 2008. We do not expect these costs to be recovered from customers in 2009.

Item 7A.

Quantitative and Qualitative Disclosures about Market Risk

Market Risk Information

Commodity Price Risk Management: We have no contracts entered into for trading purposes. Our regulated companies enter into energy contracts to serve our customers, and the economic impacts of those contracts are passed on to our customers. Accordingly, the regulated companies have no exposure to loss of future earnings or fair values due to these market risk-sensitive instruments, and the sensitivity analyses below do not include these contracts. The wholesale portfolio held by Select Energy includes contracts that are market-risk sensitive, including a wholesale sales contract with NYMPA through 2013 with approximately 2.7 million remaining MWH of sales volume, offset by related supply contracts. Select Energy also has a contract that expires in 2012 to purchase output from a generation facility. As Select Energy's contract volumes are winding down and are substantially hedged against price risks, we have somewhat limited exposure to commodity price risks.

For Select Energy s wholesale portfolio, we utilize the sensitivity analysis methodology to disclose quantitative information for our 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 our market risk-sensitive contracts 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. A portion of the fair value of the NYMPA contract is based on a model. The fair value of the generation purchase contract is based on a model using available market information.

Select Energy s Wholesale Portfolio: When conducting sensitivity analyses of the change in the fair value of the wholesale portfolio, which includes several derivative contracts and 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 percent change in forward market prices. At December 31, 2008, we calculated the market price resulting from a 10 percent change in forward market prices. A 10 percent increase in prices for all products would have resulted in a pre-tax increase in fair value of $5.6 million, and a 10 percent decrease in prices for all products would have resulted in a pre-tax decrease in fair value of $6.1 million. A 10 percent increase in energy prices would have resulted in a $1 million pre-tax decrease in fair value, and a 10 percent decrease in energy prices would have resulted in a $0.5 million pre-tax increase in fair value. A 10 percent increase/(decrease) in capacity prices would have resulted in a $1.2 million pre-tax increase/(decrease) in fair value. A 10 percent increase/(decrease) in ancillary prices would have resulted in a $5.4 million pre-tax increase/(decrease) in fair value. At December 31, 2007, a 10 percent increase in prices for all products would have resulted in a pre-tax increase in fair value of $0.9 million, and a 10 percent decrease in prices for all products would have resulted in a pre-tax decrease in fair value of $1.3 million. A 10 percent increase in energy prices would have resulted in a $6.8 million pre-tax decrease, and a 10 percent decrease in energy prices would have resulted in a $6.4 million pre-tax increase. A 10 percent increase/(decrease) in capacity prices would have resulted in a $2.2 million pre-tax increase/(decrease). A 10 percent increase/(decrease) in ancillary prices would have resulted in a $5.5 million pre-tax increase/(decrease).

The impact of a change in electricity prices on wholesale transactions at December 31, 2008 are not necessarily representative of the results that will be realized if such a change were to occur. Energy, capacity and ancillaries have different market volatilities. The method we use to determine the fair value of these contracts includes discounting expected future cash flows using a LIBOR swap curve. As such, the wholesale portfolio is also exposed to interest rate volatility. This exposure is not modeled in sensitivity analyses, and we do not believe that such exposure is material. The derivative contracts in the wholesale portfolio 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, 2008, approximately 92 percent (86 percent including 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, was 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 rate, annual interest expense would have increased by a pre-tax amount of $3.3 million. At December 31, 2008, we maintained a fixed-to-floating interest rate swap at NU parent to manage the interest rate risk associated with $263 million of its 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 that, 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 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, LOCs, and parent guarantees), and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty in the extent of default. 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, 2008 and 2007, Select Energy had cash collateral balances deposited with its NYMEX broker of $26.3 million and $18.9 million, respectively, which is included in current assets - prepayments and other on the accompanying consolidated balance sheets. Select Energy held no collateral balances from counterparties at either period end. In addition, Select Energy has a $2 million letter of credit outstanding.

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. At December 31, 2008 and 2007, our regulated companies neither held cash collateral nor deposited collateral with counterparties. PSNH has letters of credit posted as collateral with counterparties and ISO-NE. At December 31, 2008, PSNH had $85 million in letters of credit outstanding.

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 the Annual Report on Form 10-K.

Item 8.

Financial Statements and Supplementary Data

NU, CL&P, PSNH and WMECO. The consolidated Financial Statements of each of NU, CL&P, PSNH and WMECO, the accompanying combined Notes to the Financial Statements, the Report of Independent Registered Public Accounting Firm for each of NU, CL&P, PSNH and WMECO, and the respective Financial Statement Schedules filed as part of this Annual Report on Form 10-K are listed under "Item 15. Exhibits and Financial Statement Schedules" and begin on page FS-1 immediately following the signature pages of this Annual Report on Form 10-K.

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 ocurred with respect to NU, CL&P, PSNH or WMECO.

Item 9A.

Controls and Procedures

Management, on behalf of NU, CL&P, PSNH and WMECO, is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements and other sections of this combined Annual Report on Form 10-K. NU s internal controls over financial reporting were audited by Deloitte & Touche LLP. This combined annual report on Form 10-K does not include an attestation report from Deloitte & Touche LLP regarding the internal controls over financial reporting for CL&P, PSNH and WMECO. Management s report on behalf of CL&P, PSNH and WMECO was not subject to attestation pursuant to temporary rules of the SEC that permit these companies to provide only management s report in this combined annual report.

Management, on behalf of NU, CL&P, PSNH and WMECO, is responsible for establishing and maintaining adequate internal controls over financial reporting. The internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment. Under the supervision and with the participation of the principal executive officers and principal financial officer, an evaluation of the effectiveness of internal controls over financial reporting was conducted based on criteria established in *Internal Control -Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting at NU, CL&P, PSNH and WMECO were effective as of December 31, 2008.

Management, on behalf of NU, CL&P, PSNH and WMECO, undertook a separate evaluation of the design and operation of disclosure controls and procedures to determine whether they 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 management s supervision and with management s participation, including the principal executive officers and principal financial officer, as of the end of the period covered by this report on Form 10-K. The principal executive officers and principal financial officer have concluded, based on their review, that the disclosure controls and procedures of NU, CL&P, PSNH and WMECO are effective to ensure that information required to be disclosed by us in reports filed 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 management, including the 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 NU, CL&P, PSNH and WMECO during the quarter ended December 31, 2008 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, 2008, as this information has been previously disclosed in applicable reports on Form 8-K during the fourth quarter of 2008.

Part III

Item 10.

Directors, Executive Officers and Corporate Governance

The information in Item 10 is provided as of February 25, 2009 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

In addition to the information provided below concerning the executive officers of NU, incorporated herein by reference is the information to be 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 NU's definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on April 1, 2009.

NU and CL&P

The following table sets forth certain information as of February 25, 2009 concerning NU s and CL&P s executive officers. All of the Company s officers serve terms of one year and until their successors are elected and qualified

Name	**Age**	**Title**
Gregory B. Butler	51	Senior Vice President and General Counsel of NU and CL&P.
Peter J. Clarke	47	President and Chief Operating Officer and a Director of WMECO. Previously Vice President - Shared Services of NUSCO and CL&P.

Jean M. LaVecchia	57	Vice President - Human Resources of NUSCO, a subsidiary of NU.
David R. McHale	48	Executive Vice President and Chief Financial Officer of NU and CL&P.
Raymond P. Necci*	57	President and Chief Operating Officer and a Director of CL&P.
Leon J. Olivier	60	Executive Vice President and Chief Operating Officer of NU and Chief Executive Officer of CL&P.
Shirley M. Payne**	57	Vice President - Accounting and Controller of NU and CL&P.
James B. Robb	48	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	63	Chairman of the Board, President and Chief Executive Officer of NU and Chairman of CL&P.

*

Mr. Necci is an executive officer of CL&P only.

**

On February 17, 2009, Ms. Payne resigned her position and was appointed Vice President - Shared Services of NUSCO, in each case, effective April 1, 2009.

Gregory B. Butler. Mr. Butler became Senior Vice President and General Counsel of NU effective December 1, 2005, and of CL&P, PSNH and WMECO, subsidiaries of NU, effective March 9, 2006, and was elected a Director of Northeast Utilities Foundation, Inc. effective December 1, 2002. Previously Mr. Butler served as 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. Mr. Clarke was elected President and Chief Operating Officer and a Director of WMECO and a Director of Northeast Utilities Foundation, Inc., effective January 1, 2009. Previously Mr. Clarke served as Vice President of Shared Services of NUSCO, CL&P, PSNH and WMECO, from January 1, 2008 to December 31, 2008; Vice President - Customer Operations of CL&P 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.

Jean M. LaVecchia. Ms. LaVecchia was elected Vice President - Human Resources of NUSCO, effective January 1, 2005 and was elected a Director of Northeast Utilities Foundation, Inc. effective January 30, 2007. Previously Ms. LaVecchia served as Vice President - Human Resources and Environmental Services from May 1, 2001 to December 31, 2004.

David R. McHale. Mr. McHale was elected Executive Vice President and Chief Financial Officer of NU, CL&P, WMECO and PSNH, effective January 1, 2009, elected a Director of PSNH and WMECO, effective January 1, 2005, of CL&P effective January 15, 2007 and of Northeast Utilities Foundation, Inc. effective January 1, 2005. Previously, Mr. McHale served as Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO from January 1, 2005 to December 31, 2008 and Vice President and Treasurer of NU, WMECO and PSNH from July 1998 to December 31, 2004.

Raymond P. Necci. Mr. Necci was elected President and Chief Operating Officer and a Director of CL&P January 17, 2005 and a Director of Northeast Utilities Foundation effective April 1, 2006. Previously Mr. Necci served as Vice President - Utility Group Services of NUSCO from January 1, 2002 to January 16, 2005.

Leon J. Olivier. Mr. Olivier was elected Executive Vice President and Chief Operating Officer of NU effective May 13, 2008; He also has served as Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007; a Director of PSNH and WMECO since January 17, 2005 and a Director of CL&P since September 2001. Previously, Mr. Olivier served as Executive Vice President - Operations of NU from February 13, 2007 to May 12, 2008; 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. Ms. Payne was elected Vice President - Accounting and Controller of NU effective February 13, 2007, and Vice President - Accounting and Controller of CL&P, PSNH and WMECO effective January 29, 2007. Previously Ms. Payne served as 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. Mr. Robb was elected Senior Vice President, Enterprise Planning and Development of NUSCO on September 4, 2007. Previously, Mr. Robb served as 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; and Senior Vice President, Performance Management, Reliant Resources, Inc. from November 2002 to December 2003.

Charles W. Shivery. Mr. Shivery was elected Chairman of the Board, President and Chief Executive Officer of NU effective March 29, 2004; Chairman and a Director of CL&P, PSNH and WMECO effective January 19, 2007 and a Director of Northeast Utilities Foundation effective March 3, 2004. Previously, Mr. Shivery served as President (interim) of NU from January 1, 2004 to March 29, 2004; and 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.

There are no family relationships between any director or executive officer and any other trustee, director or executive officer of NU or 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. CL&P relies on NU, which has an audit committee and an audit committee 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 Trustees, 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

The information required by this Item 11 for NU is incorporated herein by reference to certain information contained in NU s definitive proxy statement for solicitation of proxies, which is expected to be filed with the SEC on or about

April 1, 2009, under the sections captioned "Compensation Discussion and Analysis" plus the related subsections, and "Compensation Committee Report" plus the related subsections following such Report.

PSNH and WMECO

Certain information required by this Item 11 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

The information in this Item 11 relates solely to CL&P. CL&P is a wholly-owned subsidiary of NU with a board of directors made up entirely of executive officers of NU system companies. CL&P does not have a compensation committee, and the Compensation Committee of NU s Board of Trustees determines compensation for the executive officers of CL&P, including their salaries, annual incentive awards and long-term incentive awards. All of CL&P s "Named Executive Officers," as defined below, with the exception of Mr. Necci, also serve as officers of other subsidiaries of NU. Compensation set by the Compensation Committee of NU and set forth herein is for services rendered to NU and its subsidiaries by such officers in all capacities.

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 the 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 its employees and the environment, and at a reasonable cost. The Executive Compensation Program supports its fundamental objective through the following design principles:

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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 NU s strategic objectives. As NU continues to grow and improve its transmission, distribution, and regulated generation systems, having the right talent will be critical.

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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.

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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 corporate 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 return on equity, 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 corporate total shareholder return.

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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 NU serves, 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 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 have the ability to 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 of CL&P listed in the Summary Compensation Table in this Annual Report on Form 10-K and whose compensation is discussed in this CD&A are referred to as the "Named Executive Officers" or "NEOs." For 2008, CL&P s Named Executive Officers are:

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Charles W. Shivery, Chairman of the Board, President and Chief Executive Officer of NU; Chairman of CL&P

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David R. McHale, Executive Vice President and Chief Financial Officer of NU and CL&P

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Leon J. Olivier, Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer and Director of CL&P

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Gregory B. Butler, Senior Vice President and General Counsel of NU and CL&P

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Raymond P. Necci, President and Chief Operating Officer of CL&P

ELEMENTS OF 2008 COMPENSATION

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

Compensation Element	Description	Objective
Base Salary	Fixed compensation	Compensate officers for fulfilling their basic job responsibilities
	Usually increased annually during the first quarter based on individual performance, competitive market levels, strategic importance of the role and experience in the position	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 corporate 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)	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: 1. Cumulative net income 2. Average return on equity 3. Average credit rating	Reward performance on key NU corporate priorities that are also key drivers of total shareholder return performance Encourage long-term thinking and commitment to the company

	4. Total shareholder return relative to a group of comparable utility companies	
Supplemental Benefits	Supplemental Executive Retirement Plan, 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: 1. A defined benefit "make-whole" plan 2. A supplemental "target" benefit (certain senior vice presidents and above only) Nonunion 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 matching contribution vests after three years or at retirement For executives hired after 2005, who are ineligible to participate in NU s	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

	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, of cash compensation that would otherwise be capped by Internal Revenue Code limits on qualified plans	
· Perquisites	Tax preparation and financial planning reimbursement benefit (except for Mr. Necci)	Encourage use of a professional tax advisor to properly prepare complex tax returns and leverage the value of NU s compensation programs
	Executive physical examination reimbursement plan	Encourage executives to undergo regular health checks to reduce the risk of losing critical employees
	Other perquisites including reimbursement of spousal travel expenses for business purposes	Discretionary benefits intended to help executive officers be more productive and efficient
Employment Agreements	Employment agreements with certain of the 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 with base salary, performance-based annual incentive compensation and long-term incentive compensation opportunities that are competitive with the market. The Compensation Committee determines the Total Direct Compensation for the Named Executive Officers as described under the caption "Market Analysis", below. As a result, the annual and long-term incentive target percentages for the NEOs 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 NU s long-term business plans and strategies, and a greater proportion of their total compensation is based on performance with a long-term focus. This survey data is discussed in greater detail below under the caption "Market Analysis."

The Compensation Committee determines total compensation for each executive officer based on the relative authority, duties and responsibilities of each office. 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 the other executive officers. As a result, Mr. Shivery s compensation is significantly higher than the compensation of the other executive officers. The Compensation Committee regularly reviews market compensation data for executive officer positions similar to those held by the 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 2008, target annual incentive and long-term incentive compensation opportunities for Mr. Shivery were 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.

The following table sets forth the contribution to 2008 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

Named Executive Officer	Base Salary	Performance Based (1) Annual Incentive	Long-Term Incentives (2) 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%
Gregory B. Butler	32%	20%	24%	24%	100%
Raymond P. Necci	43%	21%	18%	18%	100%
NEO Average, Excluding Mr. Shivery	35%	21%	22%	22%	100%

(1)

The annual incentive compensation element and performance cash awards under 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)

The percentages reflect the guideline values of RSUs at target. Actual RSUs are granted based on annual corporate and individual performance and may vary above or below target. RSUs vest over three years contingent upon continued employment.

MARKET ANALYSIS

The Compensation Committee strives to provide the executive officers with compensation opportunities over time at or above the median compensation levels for executive officers of companies comparable to NU. The Committee determined executive officer TDC levels in two steps. First, the Committee determined the "market" values of executive officer compensation elements (base salaries, annual incentives and long-term incentives) as well as total compensation using compensation data obtained from other companies. The 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 differ from median market values. Significantly, the Committee has not made an explicit commitment to compensate the executive officers through a firm and direct connection between the compensation paid by NU 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 when reviewing 2008 compensation:

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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 NU s 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 NU. Then the Committee compared utility-specific executive officer positions, including Mr. Olivier, who serves as NU s Executive Vice President and Chief Operating Officer 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 CEO, Executive Vice President and Chief Financial Officer, and Senior Vice President and General Counsel, the Committee averaged general industry comparisons with utility industry comparisons weighted equally.

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Customized peer group data. The Committee also evaluated compensation data obtained from reviews of proxy statements from the customized group of peer utility companies. Periodically, the Committee assesses the composition of the customized peer group to ensure that the number of companies is sufficient and the companies have reasonably similar revenues. The Committee also strives to maintain year over year consistency within the group. In support of executive pay decisions during 2008, the customized peer group consisted of: (i) utilities that are substantially regulated with annual revenues that ranged from $2.7 billion to $13 billion, with median annual revenues of $4.9 billion; and (ii) utilities that are less regulated and closer in size to NU, with annual revenues that ranged from $3.1 billion to $6.9 billion. Although the Committee does 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, e.g., the CEO, Chief Financial Officer, and General Counsel. For 2008, this group consisted of the following 22 companies:

Allegheny Energy, Inc.	Great Plains Energy Incorporated	Pinnacle West Capital Corporation
Alliant Energy Corporation	NiSource Inc.	PPL Corporation
Ameren Corporation	NSTAR	Progress Energy, Inc.
CenterPoint Energy, Inc.	NV Energy, Inc.	Puget Energy, Inc.
CMS Energy Corporation	OGE Energy Corp.	SCANA Corporation
Consolidated Edison, Inc.	PG&E Corporation	TECO Energy, Inc.
Energy East Corporation	Pepco Holdings, Inc.	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 2008 directly as a result of this data. In 2008, the Committee also used a subset of this group for performance comparisons under the performance cash program as described below under the caption "2008 - 2010 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 help 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 "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:

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Annual individual performance appraisals

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Market pay movement across industries (determined through market analysis)

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Targeted market pay positioning for each executive officer

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Individual experience and years of service

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Changes in corporate focus with respect to strategic importance of a position

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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, economic conditions and corporate performance have caused salary increases to be postponed. 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 the Board of Trustees a 2008 salary increase for Mr. Shivery of 3.5%, which was approved by the Board. Mr. Shivery s base salary was increased to recognize his level of contribution to the daily operations and management of the Northeast

Utilities System companies as Chief Executive Officer of NU. The Compensation Committee also approved base salary increases for the other NEOs in 2008 as follows: Mr. McHale: 11.1%; Mr. Olivier: 15.8%; Mr. Butler: 5.0%; and Mr. Necci: 3.5%. Mr. Olivier s salary increase was primarily related to his new responsibilities as Executive Vice President and Chief Operating Officer of NU effective in May 2008. Mr. McHale s salary increase was based primarily on his increased experience and individual performance during 2008. Mr. Butler s increase recognized increasing competitive pay levels for top legal professionals and his responsibilities in addition to oversight of the legal function. Mr. Necci s increase recognized his continuing significant contributions to the company.

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 the 2007 Annual Meeting of Shareholders. The annual incentive program provides cash compensation intended to reward performance under NU s 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 NU s 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 annual and long-term programs are intended to work in tandem so that achievement of NU s annual goals leads NU towards attainment of its 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.

2008 ANNUAL INCENTIVE PROGRAM

The 2008 Annual Incentive Program consisted of a corporate goal plus individual goals for each NEO. The Compensation Committee set the annual incentive compensation targets for 2008 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, we do not pay annual incentive awards if minimum levels of financial performance are not met.

If CL&P 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. Olivier, as Chief Executive Officer, and Mr. McHale, CL&P s Chief Financial Officer, to reimburse CL&P for certain incentive compensation received by each of them. To the extent that reimbursement were not required under Sarbanes-Oxley, the Incentive Plan would require any employee whose misconduct or fraud caused such restatement, as determined by the Board of Trustees, to reimburse CL&P 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.

2008 Corporate Goal

The objective of the 2008 Annual Incentive Program corporate goal for the NEOs was for NU to achieve an adjusted net income (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 corporate goal was set at 50% of target and would have occurred if actual ANI had been at least 90% of the ANI target. The maximum payout under the corporate goal was set at 200% of target and would have occurred if actual ANI had been at least 10% above the ANI target. The payment of any amount of annual incentive compensation related to individual goals required actual ANI to be at least 80% of the ANI target.

For 2008, the Compensation Committee established the ANI target at $278.8 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 corporate goals appear below (dollars in millions):

Threshold For Individual Goals (20% below ANI Target)	**Minimum Corporate Goal (10% below ANI Target)**	**2008 ANI Target**	**Maximum Corporate Goal (10% above ANI Target)**	**Actual 2008 ANI**
$223.0	$250.9	$278.8	$306.7	$291.5

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

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An assessment of the potential volatility in results through an evaluation of critical elements of the strategic business plan, both individually and in combination with each other;

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The degree of difficulty in achieving the ANI target; and

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The minimum acceptable ANI.

At the time that the Compensation Committee established the performance goals for 2008, 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 Compensation Committee approved all final exclusions from ANI. The income and expense items set forth below were excluded from ANI in 2008.

Excludable Categories	**Specific 2008 Adjustments ($ in millions)**
Changes to NU net income as the result of accounting or tax law changes	$ (3.2)
Unexpected costs related to nuclear decommissioning	
Unexpected costs related to environmental remediation at HWP	(1.7)
Impairments on goodwill acquired before 2003 (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, NU s ongoing litigation with Consolidated Edison	(25.8)
Unusual Internal Revenue Service /regulatory decisions	--
Divestiture or discontinuance of a significant segment or component of the competitive businesses	--
Acquisition of shares or assets of another entity comprising an additional segment or component of NU s business	--
Net Adjustments:	$ (30.7)

2008 Individual Goals

The 2008 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 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 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 2008

The following table sets forth the weighting of the annual incentive program corporate goal and individual goals of each NEO s compensation for 2008. These weightings reflect the Compensation Committee s desire to balance individual accountability with teamwork across the NU organization. Individual goals range from 40% to 70% of the total annual incentive program target. Certain of the 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 below.

Name and Principal Position	Corporate Goal Weighting	Individual Goal Weighting	Brief Description of Material Individual Goals
Charles W. Shivery Chairman of CL&P; Chairman of the Board, President, and Chief Executive Officer of NU	60%	40%	Ensure effective execution of NU s strategic plan and the 2008 operating and capital plans with special emphasis on meeting operational objectives (25% of individual goals).
			Develop a strategy and position NU to take advantage of opportunities beyond 2008 through the appropriate alignment of strategy, organizational structure, resources and culture. Define the company s vision with respect to climate change and implement strategies consistent with that vision. Achieve improvements in the company s reputation among its stakeholders (20% of individual goals).
			Continue progress in continued development and implementation of energy policy in New England consistent with the company s strategic plan to benefit customers. Achieve successful outcomes in federal and state regulatory and legislative proceedings to support that strategy (20% of individual goals).
			Create a strategy that brings a customer focus to the forefront of the organization; communicate expectations and standards around the customer s experience (20% of individual goals).
			Continue to implement cultural changes required for the company to succeed in an evolving environment. Define and promote a culture of safety. Lead through tone and actions NU s efforts to realize NU s vision and create an inclusive environment and a

			diverse workforce (15% of individual goals).
David R. McHale Executive Vice President and Chief Financial Officer	60%	40%	Achieve strategic initiatives: Operational planning, risk management, common equity requirements, and capital allocation (30% of individual goals).
			Achieve successful business execution: Lead efforts in rate cases, regulatory strategy, energy policy, and corporate cost analysis and management (25% of individual goals).
			Manage competitive businesses and divestiture (20% of individual goals).
			Provide internal customer service to operating companies and other corporate center groups (10% of individual goals).
			Achieve organization development goals: complete new financial planning organization; launch the Finance Academy; implement succession development plans; meet goals for safety and diversity and act on employee survey results (15% of individual goals).

Leon J. Olivier Chief Executive Officer of CL&P; Executive Vice President and Chief Operating Officer of NU	50%	50%	Execute utility operations 2008 operating budget and operating plans (45% of individual goals). Manage the New England East-West Solution project, a joint project with National Grid designed to improve reliability and electric transfer capability in Springfield, Massachusetts and central and northeast Connecticut (10% of individual goals). Work with the Chief Executive Officer of NU and members of NU s executive team to build stakeholder confidence (10% of individual goals). Implement customer experience initiatives and complete the customer service integration for the operating companies (15% of individual goals). Establish a company-wide safety culture that promotes an environment where safety is valued by every employee (10% of individual goals). Advance the company s strategic objectives and implement appropriate actions surrounding climate change (10% of individual goals).
Gregory B. Butler Senior Vice President and General Counsel	50%	50%	Manage Legal Department to enable the company to achieve its strategic plan and 2008 operating and capital financing objectives (20% of individual goals).

Improve the company s corporate position through enhanced communications focused on building the company s reputation among various stakeholders (20% of individual goals).

Achieve successful outcomes in federal and state energy regulatory policy and ratemaking proceedings (20% of individual goals).

Influence, support and provide expertise for the company s strategic initiatives and emerging opportunities (20% of individual goals).

Stewardship goals including response to employee survey results, response to climate change factors, and contribute to enhancing a diverse and inclusive environment (10% of individual goals).

Support operating companies and other Corporate Center groups to balance business initiatives, cost and customer service stewardship (10% of individual goals).

Raymond P. Necci President & Chief Operating Officer	30%	70%	Maximize CL&P and Yankee Gas net income performance (20% of individual goals). Achieve a successful outcome in an external agency audit of CL&P s electric distribution system (10% of individual goals). Successfully implement a series of customer experience initiatives and complete CL&P s new customer service system (20% of individual goals). Pursue strategic goals, including energy conservation and load management initiatives (10% of individual goals). Implement strategies designed to increase engagement of employees and labor unions, and to improve safety performance (20% of individual goals). Execute operational goals, including completion of scheduled maintenance, energy efficiency, and reliability projects, and managing operation and maintenance expenditures (20% of individual goals).

2008 Results

The 2008 actual ANI was $291.5 million, which exceeded the target ANI amount for the annual program corporate goal, but was less than the maximum ANI amount. As a result, a portion of the total annual incentive payment to each

NEO was attributable to achieving NU s corporate goal at 146% of target. In addition, the 2008 actual ANI 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.

Mr. Shivery s Annual Incentive Payment

The Compensation Committee and the Corporate Governance Committee of NU s Board of Trustees 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:

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Mr. Shivery s execution of NU s long-term strategic plan as well as NU s 2008 operating and capital plans was well above expectations. CL&P completed all of its remaining southwest Connecticut transmission projects. The major project, the 69-mile transmission line between Middletown and Norwalk Connecticut, was completed one year ahead of schedule and below budget. NU achieved successful outcomes in various legislative and regulatory proceedings, including obtaining an order from the Federal Energy Regulatory Commission providing a favorable base return on equity and incentives, including one for the use of advanced technologies. Implementation of the $6 billion capital investment program is on track and has yielded increased earnings and improved reliability. Distribution, generation and the new liquefied natural gas facilities operated reliably.

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Mr. Shivery s work toward developing NU s strategy and positioning NU for the future was well above expectations. NU proposed jointly with NSTAR the Hydro-Québec project, a visionary long-term project to deliver low-carbon power to New England over a new transmission line between northern New England and Hydro-Québec in eastern Canada. NU continues to remain financially strong in the face of extreme disruptions in the financial markets. Significant positive steps were taken to improve the company s culture of performance and accountability and expand leadership visibility. Key members of management were assigned to positions with new or expanded responsibilities in order to increase their overall experience and better position NU for continued success. NU continued to improve in enterprise risk management and communications strategy and execution.

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Mr. Shivery s role in energy policy initiatives in New England met expectations at both the federal and state levels. Of particular note were various programs to reduce the environmental impact of electricity generation, including the Hydro-Québec project with NSTAR, which is expected to provide a competitive source of clean power that is favorable in comparison to current alternatives; preliminary work to obtain approval for solar generation as permitted by the Massachusetts Green Communities Act; initiation of an advanced metering infrastructure pilot program in Connecticut; and continued progress on the Northern Loop project in New Hampshire, all of which are expected to provide long-term benefits to NU s customers and communities and competitive returns to NU s investors. NU continued to help shape legislative policy related to climate change. 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.

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On balance, Mr. Shivery s performance regarding customer focus goals met expectations. NU recruited a new customer experience officer who oversaw the strengthening of NU s customer service organization, including developing a customer experience vision, establishing standards of service excellence, and implementing NU s customer service integration system. In addition, NU undertook extensive regulatory and stakeholder outreach.

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Mr. Shivery s efforts to align the company s culture with NU s business strategies, improve safety performance and increase diversity met expectations. Increased focus was placed on development of leaders at all levels, and on development of critical engineering and financial talent to ensure the continuity of institutional knowledge critical to NU s success. NU s safety performance improved measurably in 2008. An increase in diversity at multiple leadership levels and throughout the organization was achieved.

The Compensation Committee and the Corporate Governance Committee 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. Following a detailed review of these factors without Mr. Shivery present, the Board of Trustees awarded Mr. Shivery an annual incentive payment of $1,519,129 for 2008, consisting of $935,046 attributable to the achievement of 146% of the corporate goal and an additional $584,083 attributable to Mr. Shivery s performance of his individual goals. The Board of 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 2008. Mr. Shivery s annual incentive payment exceeds that of the other NEOs because of his significantly greater duties and responsibilities as CEO of NU.

NEO Annual Incentive Payments

In addition to our 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 NU's corporate success and growth. The annual incentives paid to each NEO as described below include the corporate ANI goal component for 2008.

The Compensation Committee determined that Mr. McHale and his organization provided critical guidance and support for NU's strategies involving the Northern Solutions and Hydro-Québec major transmission projects, the Massachusetts Green Communities Act, and Connecticut peaking generation. Mr. McHale and his team took significant positive steps to ensure that NU remained financially strong despite extreme disruptions in the financial markets. Current credit ratings and rating agency outlooks on NU and NU's four regulated utilities were maintained despite significant capital expenditure projections and volatile market conditions. In addition, Mr. McHale s organization implemented the NU Finance Academy, which is designed to strengthen employees business knowledge in support of NU's organization development efforts. Finally, Mr. McHale and his team successfully managed the market risk of NU's competitive businesses while achieving above-budget net income. Based on his demonstrated leadership and this assessment of his successes, the Compensation Committee awarded Mr. McHale an annual incentive payment of $465,520 for 2008.

The Compensation Committee determined that Mr. Olivier and his team effectively executed NU's operating plan and the 2008 components of NU's five-year strategic plan, including the early and below-budget completion of the Middletown-Norwalk transmission line, significant safety improvements, and effective completion of the year s capital program. In addition, through their actions, Mr. Olivier and his team were successful in increasing NU's external stakeholders understanding of the benefits of NU's strategies around meeting the resource, environmental and energy supply needs of NU's region. Mr. Olivier and his team also made significant progress in improving customer experience, including the completion and launch of NU's integrated customer service system and an extensive reorganization of the customer experience organization. Based on his demonstrated leadership and the Committee s assessment of his successes, the Committee awarded Mr. Olivier an annual incentive payment of $494,571 for 2008.

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 provided extensive support for various strategic initiatives, including the Northern Solutions and Hydro-Québec major transmission projects and the Massachusetts Green Communities Act. Mr. Butler and his team contributed significantly to NU's regulatory and financial strategies by achieving favorable outcomes in various federal and state regulatory proceedings. His team also supported NU's operating subsidiaries as each of them executed their operating plans. Based upon these successes, the Compensation Committee awarded Mr. Butler an annual incentive payment of $361,286 for 2008.

The Compensation Committee determined that, on balance, Mr. Necci and his team executed the operating plan successfully, with highly reliable operations of the electric distribution system and the new liquefied natural gas facility. Mr. Necci and his team also completed a high volume of important maintenance and capital projects. Mr. Necci and his team partnered with bargaining unit employees and generally increased employee participation in creative efforts to improve service, safety, and reliability. These results yielded significant benefits to both customers and shareholders. Based on his demonstrated leadership and the Committee s assessment of his successes, the Committee awarded Mr. Necci an annual incentive payment of $173,807 for 2008.

LONG-TERM INCENTIVE PROGRAM

General

Under NU s Long-Term Incentive Programs, the Compensation Committee acting jointly with the Corporate Governance Committee recommends to the Board of Trustees a long-term incentive target grant value for Mr. Shivery as a percentage of base salary on the date of grant. This recommendation is forwarded to the Board for approval. The Compensation Committee also approves 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 typically consists 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 the 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 2008, the Compensation Committee acting jointly with the Corporate Governance Committee recommended to the Board of Trustees a long-term incentive compensation target for Mr. Shivery at 300% of base salary, which the Board 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.

Restricted Share Units (RSUs)

Each RSU granted under the long-term incentive program entitles the holder to receive one NU common share at the time of vesting. All RSUs granted in 2008 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 common shares. Dividend equivalents are accounted for as additional common shares that accrue and are distributed with the common shares issued upon vesting of the underlying RSUs.

General

Annually, the Compensation Committee determines RSU grants for each executive officer participating in the long-term incentive program. Initially, the target RSU grants are equal to one-half of the long-term incentive compensation target for each executive officer. RSU grants are based on a percentage of base salary and measured in dollars. The percentage used for each executive officer is based on the executive officer s position in the company and ranges from 17.5% to 75% of salary, except for Mr. Shivery, whose percentage is set at 150%. The aggregate dollar amount of the RSU grants at target for each executive officer 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 overall corporate performance during the preceding fiscal year. In its discretion, the Committee may also increase or decrease RSU grants for individual executive officers 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 the Board of Trustees the final RSU grant for Mr. Shivery. Based on input from Mr. Shivery, the Compensation Committee determines the final RSU grants for each of the other executive officers, including the other NEOs. Increases or decreases to target RSU grants for the executive officers will increase or decrease their compensation as compared to the compensation of executive officers of utilities listed in the customized peer group. Increases or decreases to individual target RSU grants 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.

2008 RSU Grants

For 2008, the target RSU Pool totaled approximately $4.4 million, representing the sum of all RSU grants, at target, for all 27 executive officers participating in the long-term incentive program. The Committee decided to increase the target RSU Pool based on NU s financial, operational and strategic performance during 2007. The Committee, using its judgment and experience, subjectively determined that NU s performance in 2007 both improved NU s strategic position and enhanced shareholder value. The Committee approved individual RSU grants for the executive officers, excluding Mr. Shivery, that totaled 113% of target. These grants were based on input from Mr. Shivery, the Committee s subjective assessment of each executive officer s individual performance and contribution to NU s long-term strategic direction in 2007, and the desire to motivate each executive officer s future performance. The Compensation Committee acting jointly with the Corporate Governance Committee recommended to the Board of Trustees an RSU grant for Mr. Shivery of 125% of target based on NU s corporate performance in 2007 and the Committees subjective assessment of Mr. Shivery s individual performance and contributions to NU s long-term strategic direction in 2007. The final RSU Pool for executive officers, including Mr. Shivery, totaled approximately $5.2 million, or 117% of target. Dividing the final RSU Pool by $28.40, the average closing price for NU common shares during the last ten trading days in January 2008, resulted in an aggregate of 181,846 RSUs. The following RSU grants were approved, reflected as a percentage of target and in RSUs, based on individual performance and contributions: Mr. Shivery: 125% (68,332 RSUs); Mr. McHale: 125% (16,505 RSUs); Mr. Olivier: 125% (14,717 RSUs); Mr. Butler: 110% (11,823 RSUs); and Mr. Necci: 105% (4,860 RSUs).

Share Ownership Guidelines

Effective in 2006, the Compensation Committee approved share ownership guidelines to emphasize the significance of increased share ownership by certain of NU s executive officers. The Committee subsequently reviewed the guidelines for these executive officers and determined that they remain reasonable and require no modification.

Executive Officer	**Ownership Guidelines (Number of Shares)**
CEO of NU	200,000
NU EVPs/SVPs	30,000 - 45,000
NU subsidiary presidents and key department heads	17,500

At the time the share ownership guidelines were implemented, the Committee required NU s executive officers to attain these ownership levels within five years. The Committee requires all newly-elected executive officers to attain the ownership levels within seven years. All of the 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 NU s 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, except as reduced in the discretion of the Compensation Committee. The Compensation Committee determines the actual amounts payable, if any, only after the end of the final year in the respective program.

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Cumulative Adjusted Net Income, which is consolidated NU net income adjusted by the Compensation Committee to exclude the effects of certain nonrecurring income and expense items or events (which was defined as ANI under the annual incentive program) over the three years in a program.

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Average adjusted ROE, which is the average of the annual return on equity for the three years in a program. The Committee adjusts average ROE on the same basis as cumulative adjusted net income.

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Average credit rating of NU (excluding the regulated utilities), 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 of NU by S&P and Moody s must remain above investment grade.

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Relative total shareholder return of NU 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 the 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 relative total shareholder return to emphasize to the plan participants the importance of achieving total shareholder returns that are comparable to the returns for companies listed in the 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 performance peer group.

The performance peer groups used by the Committee for performance comparisons under each of the three Performance Cash Programs in effect during 2008 and described below consisted of a subset of the customized peer group described earlier under "Market Analysis". The performance peer group companies for each program are listed in footnote 1 accompanying each table. The performance peer groups represent companies with investment profiles, including growth potential, business models and areas of focus substantially similar to NU s. The Committee compared NU s total shareholder return to the total shareholder returns of the companies in the performance peer group. The customized peer group has historically been larger than the performance peer groups because NU competes for talent with more companies than those with which it competes for investment. However, beginning with the 2009 - 2011 Long-Term Incentive Program, to simplify the peer group structure, the Committee is using the full customized peer group to evaluate the total shareholder return metric. See "2009 Changes."

2006 - 2008 Performance Cash Program

The Compensation Committee approved the 2006 - 2008 Performance Cash Program in early 2006. Upon completion of the fiscal year ended 2008, 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 138% of target.

The 2006 - 2008 program included goals in four metrics: cumulative adjusted net income, average adjusted ROE, average credit rating, and relative total shareholder return, as described below. For the 2006 - 2008 program, cumulative adjusted net income and average adjusted ROE excluded the positive and negative effects of the following nonrecurring income and expense items or events: divestiture or discontinuance of a segment or component of NU s business and net income associated with NU Enterprises.

The table set forth below describes the goals under the 2006 2008 program and NU s actual results during that period:

	2006 2008 Program Goals			
Goal	**Minimum**	**Target**	**Maximum**	**Actual Result**
Cumulative Adjusted Net Income ($ in millions)	$531.3	$557.9	$585.4	$733.5
Average Adjusted ROE	7.4%	7.8%	8.1%	8.9%
Average Credit Rating	1.2	1.7	2.2	1.7
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th	86th

(1)

The performance peer group for the 2006 2008 program included NU and the following companies: Allegheny Energy, Inc., Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., Consolidated Edison Inc., Energy East Corporation, KeySpan Corporation, NiSource Inc., NSTAR, NV Energy, Inc., Pinnacle West Capital Corporation, Pepco Holdings Inc., Puget Energy, Inc., SCANA Corporation, Wisconsin Energy Corporation, and Xcel Energy Inc.

Based on NU s financial performance during the three-year performance period of the 2006 2008 Performance Cash Program, the Committee approved the following payments: Mr. Shivery: $1,738,800; Mr. McHale: $284,694;

Mr. Olivier: $345,000; Mr. Butler: $362,388; and Mr. Necci: $161,322. The payments were determined pursuant to formulas set forth in the 2006 - 2008 Performance Cash Program and were not subject to the discretion of the Compensation Committee.

2007 - 2009 Performance Cash Program

The Committee approved the 2007 - 2009 Performance Cash Program goals in early 2007. The Committee will determine whether any amounts are payable after the end of the 2009 fiscal year, which is the final year in the three-year program.

The 2007 - 2009 program also includes goals in four metrics: cumulative adjusted net income, average adjusted ROE, average credit rating, and relative total shareholder return, as described below. For the 2007 – 2009 program, cumulative adjusted net income and average adjusted ROE exclude the positive and negative effects of the following nonrecurring income and expense items or events: accounting or tax law changes; unusual Internal Revenue Service or regulatory issues; unexpected changes in costs related to nuclear decommissioning; unexpected changes in 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 NU s litigation settlement with Consolidated Edison, Inc.

The table set forth below describes the goals under the 2007 - 2009 program:

2007 - 2009 Program Goals

Goal	**Minimum**	**Target**	**Maximum**
Cumulative Adjusted Net Income ($ in millions)	$753.2	$836.9	$920.6
Average Adjusted ROE	8.4%	9.2%	10.0%
Average Credit Rating	1.2	1.7	2.2
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th

(1)

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, NV Energy, Inc., Pepco Holdings, Inc., Pinnacle West Capital Corporation, Puget Energy, Inc., SCANA Corporation, Wisconsin Energy Corporation and Xcel Energy Inc.

2008 2010 Performance Cash Program

The Committee approved the 2008 2010 Performance Cash Program goals in early 2008. The Committee will determine whether any amounts are payable after the end of the 2010 fiscal year, which is the final year in the three-year program.

The 2008 - 2010 program also includes goals in four metrics: cumulative adjusted net income, average adjusted ROE, average credit rating, and relative total shareholder return, as described below. For the 2008 - 2010 program, cumulative adjusted net income and average adjusted ROE exclude the positive and negative effects of the following nonrecurring income and expense items or events: accounting or tax law changes; unusual Internal Revenue Service or regulatory issues; unexpected changes in costs related to nuclear decommissioning; unexpected changes in costs related to environmental remediation of the HWP; divestiture or discontinuance of a segment or component of NU s business; the acquisition of shares or assets of another entity comprising an additional segment or component of NU s business; impairments on goodwill acquired before 2003 (more than five years prior to the beginning of this program cycle); and the impact of NU s litigation settlement with Consolidated Edison, Inc.

The table set forth below describes the goals under the 2008 - 2010 program:

	2008 2010 Program Goals		
Goal	**Minimum**	**Target**	**Maximum**
Cumulative Adjusted Net Income ($ in millions)	$845.7	$939.7	$1,033.7
Average Adjusted ROE	8.6%	9.5%	10.5%
Average Credit Rating	1.2	1.7	2.2
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th

(1)

The performance peer group for the 2008 - 2010 program includes NU and the following companies: Allegheny Energy, Inc., Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., CMS Energy Corporation, Consolidated Edison, Inc., NiSource, Inc., NSTAR, NV Energy, Inc., Pepco Holdings, Inc., Pinnacle West Capital Corporation, SCANA Corporation, TECO Energy, Inc., Wisconsin Energy Corporation and Xcel Energy Inc.

2009 CHANGES

Customized Peer Group

As discussed previously under the caption "Market Analysis," to the extent practicable, year over year peer group consistency is important, because a large shift in peer company demographics can materially affect competitive compensation findings. While the Compensation Committee strives to maintain a consistent set of peer companies from year to year to avoid volatility in competitive compensation findings used for comparison across companies, the Committee modified the peer group for 2009. The modifications were necessary because the Committee changed its selection criteria. In the past, as described previously, the Committee had differentiated among utilities that were "substantially regulated" and "less regulated." This distinction proved to be unnecessary and complex because NU competes for executive talent with peer utility companies having different levels of regulated utility business. Therefore, the Compensation Committee decided to stop considering this criterion for the peer group beginning in 2009. However, the Committee continued to apply the size criterion (revenue between $3 billion and $13 billion). As a result, the new peer group includes the addition of two new peer utility companies, Integrys Energy Group Inc. and DTE Energy Company, and the removal of two companies, PPL Corporation and PG&E Corporation. The Committee also removed two additional companies, Puget Energy, Inc. and Energy East Corporation, due to pending or finalized acquisitions.

Furthermore, in an effort to simplify the peer group structure, beginning in 2009, the Committee is using the same customized peer group for both market analysis and performance comparisons.

The Committee s review of these minor changes to the customized peer group indicates that it would not have materially affected the historical results of the market analyses or the results of the Performance Cash component of the long-term incentive programs.

2009 - 2011 Long-Term Incentive Program

In 2009, the Compensation Committee changed the components of the long-term incentive program to strengthen the connection between compensation and performance. For the 2009 - 2011 Long-Term Incentive Program, the grant value at target consisted of 25% RSUs, 25% performance shares, and 50% performance cash. Performance shares are performance units denominated in NU common shares that replace half of the targeted RSU grant from previous programs. Like performance cash, performance shares will be distributed only at the end of the three-year performance period, and the actual number of shares will vary from target based on performance against the same four equally-weighted corporate goals. No shares will be distributed if none of the goals is met.

Prior to 2009, in the event of a change of control, NU s long-term incentive programs provided for the vesting, pro rata based on the number of days of employment during the performance period, and payment of performance cash at target, whether or not the executive s employment terminated, unless the Committee determined otherwise. Commencing with the 2009 - 2011 Long-Term

Incentive Program, in the event of a change of control after which an executive s employment does not terminate, actual performance share awards and performance cash awards will be determined based on the measurement of the four metrics up to the effective date of the change of control. In such event, actual awards will be reduced pro rata based on the number of days from program commencement until the effective date of the change of control. Awards will continue to be distributed only at the end of the three-year program period. However, if the executive s employment terminates within 24 months following the change of control, but before the end of the three-year performance period, then the executive will receive the full award, payable immediately, as if performance had been at target.

SUPPLEMENTAL BENEFITS

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

RETIREMENT BENEFITS

NU provides retirement income benefits for employees, including executive officers, who commenced employment before 2006 under the Northeast Utilities Service Company Retirement Plan (Retirement Plan) and, for officers, under the Supplemental Executive Retirement Plan 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 nonofficer annual incentives up to the Internal Revenue Code limits for qualified plans. Beginning in 2006, newly-hired nonunion employees, including executive officers, participate in an enhanced defined contribution retirement program in the Northeast Utilities Service Company 401k Plan (401k Plan), called the K-Vantage benefit, instead of participating in 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, compensates 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 Mr. Olivier and Mr. 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 for five years and until age 60, unless the 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 retirement health benefits. In addition, the Named Executive Officers are eligible to receive certain health and welfare benefits upon termination of employment following a change of control or, for Messrs. Shivery, Olivier, McHale and Butler, an involuntary termination of employment. To the extent such benefits may not be provided through NU s tax qualified plans, the executive is entitled to participate in a non-qualified health plan that will be treated as taxable compensation to the executive officer to the extent of company contributions and will be provided with a tax gross-up so that the value to the executive is equivalent to a tax qualified plan benefit. 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 "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. Mr. Necci s offer of employment provided for an extra nine months of service in calculating his pension benefits.

401K PLAN

NU provides an opportunity for employees to save money for retirement on a tax-favored basis through the 401k Plan. The 401k Plan is a defined contribution qualified plan under the Internal Revenue Code and contains a cash or deferred arrangement 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 an eligible employee s 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 in the Nonqualified Deferred Compensation Plan (Deferral Plan) that provides defined contribution benefits above Internal Revenue Code limits on qualified plans.

NONQUALIFIED DEFERRED COMPENSATION PLAN

NU s executive officers participate in the 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 matching contribution is deemed to be invested in common shares and vests at the end of the third year after the calendar year in which the matching contribution 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, except for investments in NU common shares. 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 Revenue 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 NU s philosophy that perquisites should be provided to executive officers only as needed for business reasons, and not simply in reaction to prevalent market practices.

The NEOs (except for Mr. Necci), 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, properly prepare complex tax returns, and leverage the value of NU s 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 $800 for fees incurred beyond those covered by NU s 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 so that relocation is cost neutral to the executive officer.

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 In 2008, tax gross-ups were provided for spousal travel expense reimbursement because of the corporate benefit to NU when executive officers incurred such expenses. The aggregate amount of the tax gross-ups was well below prevalent market practices and the impact of them was not material to NU. Commencing in 2009, NU will no longer pay gross-ups for taxes on any perquisites other than for taxes on reimbursement of relocation expenses for newly-hired or transferred executives.

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. These termination and change of control benefits were in prevalent practice at the time the agreements were signed and were necessary to attract and retain competent and capable executive talent. NU continues to believe that these benefits help to ensure the executive officers 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 with Messrs. Shivery, McHale and Butler 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 s 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 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. Mr. Olivier s employment agreement does not provide for severance payments in the event that his employment terminates following a change of control. Mr. Olivier and Mr. Necci participate instead in the Special Severance Program.

As defined in the employment agreements with Messrs. Shivery, McHale and Butler, a "change of control" means a change in ownership or control of NU 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 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 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.

Pursuant to the change of control provisions in the employment agreements, each NEO except for Mr. Olivier and Mr. 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. Mr. Olivier s and Mr. Necci s severance payments may be reduced to avoid excise taxes.

We describe and explain how the appropriate payment and benefit levels are determined under the various circumstances that trigger payments or provision of benefits in the tables and accompanying footnotes appearing in the section captioned "Potential Payments Upon Termination or Change of Control," below.

To help protect NU 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 solicit NU s employees for a period of two years (one year for Mr. Olivier and Mr. 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 the 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 Deferral 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 "Supplemental Benefits" above, NU s employment agreements with Messrs. Shivery and Olivier also include additional retirement benefits payable upon voluntary termination of employment.

TAX AND ACCOUNTING CONSIDERATIONS

Tax Considerations. All executive compensation for 2008 was fully deductible by NU for federal income tax purposes, except for approximately $330,000 paid to Mr. Shivery, consisting of restricted share and RSU distributions of approximately $280,000 and salary and reimbursements of approximately $50,000.

Section 162(m) of the Internal Revenue Code limits the tax deduction for compensation paid to a company s CEO 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, until the calendar year after he leaves the Company, at which time Section 162(m) will no longer apply to him. The non-deductible restricted share and RSU distributions for Mr. Shivery in 2008 described above relate to restricted share and 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, executive employment agreements, severance arrangements, and other nonqualified deferred compensation plans were amended in 2008 to satisfy the requirements of Section 409A.

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, the 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 Mr. Olivier and Mr. 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 payments are set forth in the tables found under the caption "Potential Payments upon 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 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 in "Management s Discussion and Analysis and Results of Operations" in this Annual Report on Form 10-K. 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.

SUMMARY COMPENSATION TABLE

The table below summarizes the total compensation paid or earned by Mr. Olivier, CL&P s Chief Executive Officer (CEO), Mr. McHale, CL&P s Executive Vice President and Chief Financial Officer (CFO), and the three other most highly compensated executive officers, other than the CEO and CFO, who were serving as executive officers at the end of 2008, including Mr. Shivery, NU s Chairman, President and Chief Executive Officer (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, 2008. The compensation shown for each Named Executive Officer was for all services in all capacities to NU and its subsidiaries. All salaries, annual incentive amounts and long-term incentive amounts shown for each Named Executive Officer were paid for all services rendered to NU and its subsidiaries in all capacities.

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 Compen-sation ($) (7)	Total ($)
	2008	1,067,404		2,106,065		3,257,929	1,627,493	35,397	8,094,288

Charles W. Shivery							
Chairman of CL&P; Chairman of the Board, President and Chief Executive Officer of NU	2007	987,308	1,779,313	3,048,360	1,326,931	49,026	7,190,938
	2006	918,846	1,061,205	1,698,395	1,274,011	40,691	
David R. McHale	2008	508,654	406,677	750,214	514,753	9,907	2,190,205
Executive Vice President and Chief Financial Officer (8)	2007	434,135	296,891	755,810	614,481	7,603	
	2006	353,847	148,512	395,693	413,275	6,600	
Leon J. Olivier	2008	550,962	399,123	839,571	324,854	18,997	2,133,507
Chief Executive Officer of CL&P; Executive Vice President and Chief Operating Officer	2007	462,096	306,115	777,226	251,556	15,042	
	2006	411,039	178,951	451,419	275,264	13,692	
Gregory B. Butler	2008	418,542	354,393	723,674	206,850	8,207	1,711,666
Senior Vice President and General Counsel	2007	382,244	319,716	731,950	195,321	12,941	
	2006	359,659	218,078	383,279	215,642	7,077	
Raymond P. Necci	2008	319,000	149,395	335,129	224,438	9,922	1,037,884
President and Chief Operating Officer	2007	295,846	129,195	346,850	309,856	9,299	1,091,046
	2006	282,589	103,307	200,229	191,963	8,898	786,986

(1)

Includes amounts deferred in 2008 by the Named Executive Officers under the Deferral Plan, as follows: Mr. Shivery: $32,022; Mr. Olivier: $137,741; and Mr. Necci: $63,800. For more information, see the Executive Contributions in the Last Fiscal Year column of the Non-Qualified Deferred Compensation Plans Table.

We pay each of our salaried employees, including each of the Named Executive Officers, 1/26th of their annual base salary every two weeks. This bi-weekly pay schedule typically results in one extra pay date per year approximately once every twelve years. Accordingly, the amounts reported for Salary for each Named Executive Officer in 2008 reflect 27 pay dates, as compared to 26 pay dates in each of 2007 and 2006.

(2)

No discretionary bonus awards were made to any of the Named Executive Officers in the fiscal years ended 2006, 2007 and 2008.

(3)

Reflects the dollar amounts recognized for financial statement reporting purposes for the fiscal year ended December 31, 2008, 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 2008. Assumptions used in the calculation of this amount appear in the "Management s Discussion and Analysis and Results of Operations" in this Annual Report on Form 10-K.

In 2005, 2006, 2007 and 2008, the Named Executive Officers were granted RSUs that vest in equal annual installments over three years as long-term incentive compensation. NU defers the distribution of common shares upon vesting of RSUs granted to Mr. Shivery, until the calendar year after he leaves the Company. 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.

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 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. In addition, upon his appointment as NU s Chairman, President and CEO in 2004, Mr. Shivery was granted 25,000 restricted shares that vested in equal annual installments over four years. NU paid dividends on these restricted shares during the vesting period to the same extent that dividends are declared and paid on NU s common shares.

(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 2008.

(5)

Includes payments to the Named Executive Officers under the 2008 Annual Incentive Program (Mr. Shivery: $1,519,129; Mr. McHale: $465,520; Mr. Olivier: $494,571; Mr. Butler: $361,286; and Mr. Necci: $173,807). Also includes payments under the 2006 - 2008 Long-Term Incentive Program (Mr. Shivery: $1,738,800; Mr. McHale: $284,694; Mr. Olivier: $345,000; Mr. Butler: $362,388; and Mr. Necci: $161,322). Performance goals under the 2008 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 2008. 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 Named Executive Officers) in February 2009. Performance goals under the 2006 - 2008 Long-Term 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 2006. The Compensation Committee determined the extent to which the long-term goals were satisfied in February 2009.

(6)

Includes the actuarial increase in the present value from December 31, 2007 to December 31, 2008 of the Named Executive Officer s accumulated benefits under all of NU s defined benefit pension plans determined using interest rate and mortality rate assumptions consistent with those appearing in the "Management s Discussion and Analysis and Results of Operations" in this Annual Report on Form 10-K. The Named Executive Officer may not be fully vested in such amounts. 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 2008.

(7)

Includes matching contributions of $6,900 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, 2008 (Mr. Shivery: $25,122; Mr. Olivier: $9,629; and Mr. Necci: $2,670), plus tax gross-ups for wireless handheld and cell phone fees (Mr. Shivery: $707; Mr. McHale: $717; Mr. Olivier: $977; Mr. Butler: $977 and Mr. Necci: $352); and tax gross-ups for spousal travel expenses (Mr. Shivery: $2,669; Mr. McHale: $2,290; Mr. Olivier: $1,491; and Mr. Butler: $329). Mr. McHale and Mr. Butler did not participate in the Deferred Compensation Plan.

(8)

Mr. McHale was elected Executive Vice President and Chief Financial Officer of CL&P and NU effective January 1, 2009. He served as Senior Vice President and Chief Financial Officer of CL&P and NU from January 1, 2005 until January 1, 2009.

GRANTS OF PLAN-BASED AWARDS DURING 2008

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, 2008. 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 2008.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards				
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	All Other Stock Awards: Number of Shares of Stock or Units (#) (3)	Grant Date Fair Value of Stock and Option Awards ($) (4)
Charles W. Shivery						
Annual Incentive (1)	2/12/2008	533,702	1,067,404	2,134,808		
Long-Term Incentive (2)	2/12/2008	776,250	1,552,500	2,328,750	68,332	1,891,430
David R. McHale						
Annual Incentive (1)	2/12/2008	165,313	330,625	661,250		
Long-Term Incentive (2)	2/12/2008	187,500	375,000	562,500	16,505	456,858
Leon J. Olivier						
Annual Incentive (1)	2/12/2008	179,063	358,125	716,250		
Long-Term Incentive (2)	2/12/2008	167,187	334,375	501,562	14,717	407,367
Gregory B. Butler						
Annual Incentive (1)	2/12/2008	136,026	272,052	544,104		
Long-Term Incentive (2)	2/12/2008	152,621	305,241	457,862	11,823	327,261
Raymond P. Necci						
Annual Incentive (1)	2/12/2008	79,750	159,500	319,000		
Long-Term Incentive (2)	2/12/2008	65,730	131,459	197,189	4,860	134,525

(1)

Amounts reflect the range of potential payouts, if any, under the 2008 Annual Incentive Program for each Named Executive Officer, as described in the Compensation Discussion and Analysis. The payment in 2009 for performance in 2008 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 2008 - 2010 Long-Term Incentive Program, as described in the Compensation Discussion and Analysis. Grants of three-year performance cash awards were made to officers during 2008 under the 2008 - 2010 Long-Term Incentive Program. Performance cash will be fully vested at the end of the performance period and paid to the officer in cash 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 12, 2008 under the 2008 - 2010 Long-Term Incentive Program. The RSUs will vest in equal installments on February 25, 2010, 2011 and 2012. Except for Mr. Shivery, NU will distribute common shares in respect to 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 to vested RSUs in three approximately equal annual installments beginning the later of (i) six months after he leaves the company and (ii) January of the calendar year after he leaves the company. 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. The Annual Incentive Program does not include an equity component.

(4)

Reflects the grant-date fair value of RSUs granted to the Named Executive Officers on February 12, 2008, under the 2008 2010 Long-Term Incentive Program determined pursuant to generally accepted accounting principles. The Annual Incentive Program does not include an equity component.

EQUITY GRANTS OUTSTANDING AT DECEMBER 31, 2008

The following table sets forth option and RSU grants outstanding at the end of our fiscal year ended December 31, 2008 for each of the Named Executive Officers. All outstanding options were fully vested as of December 31, 2008.

	Option Awards (1)			Stock Awards (2)	
Name	**Number of Securities Underlying Unexercised Options Exercisable (#)**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock that have not Vested (#) (3)**	**Market Value of Shares or Units of Stock that have not Vested ($)(4)**
Charles W. Shivery	29,024	18.90	6/11/2012	166,827	4,013,868
David R. McHale				34,771	836,587
Leon J. Olivier				31,217	751,071
Gregory B. Butler				26,724	642,985
Raymond P. Necci				10,748	258,596

(1)

NU has not granted stock options since 2002.

(2)

Awards and market values of awards appearing in the table and the accompanying notes have been rounded to whole units.

(3)

An aggregate of 137,653 unvested RSUs vested on February 25, 2009 (Mr. Shivery: 86,056; Mr. McHale: 16,902; Mr. Olivier: 15,361; Mr. Butler: 13,728; and Mr. Necci: 5,606). An additional 92,590 unvested RSUs will vest on February 25, 2010 (Mr. Shivery: 57,230; Mr. McHale: 12,183; Mr. Olivier: 10,785; Mr. Butler: 8,923; and Mr. Necci: 3,467). An additional 40,044 unvested RSUs will vest on February 25, 2011 (Mr. Shivery: 23,541; Mr. McHale:

5,686; Mr. Olivier: 5,070; Mr. Butler: 4,073 and Mr. Necci: 1,674).

(4)

The market value of RSUs is determined by multiplying the number of share units by $24.06, the closing price per share of NU common shares on December 31, 2008, the last trading day of the fiscal year.

OPTIONS EXERCISED AND STOCK VESTED IN 2008

The following table reports amounts realized on equity compensation during the fiscal year ended December 31, 2008. None of the Named Executive Officers exercised options in 2008. The Stock Awards columns report the vesting of restricted share grants and RSU grants to the Named Executive Officers in February 2008.

	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			87,901	2,383,885
David R. McHale			14,483	392,774
Leon J. Olivier			15,281	414,423
Gregory B. Butler			16,334	442,970
Raymond P. Necci			6,581	178,488

(1)

Represents the amounts realized upon option exercises, which is the difference between the option exercise price and the market price at the time of exercise.

(2)

Includes 6,250 restricted shares granted to Mr. Shivery upon his appointment as NU s Chairman, President and CEO in 2004, for which restrictions lapsed in 2008.

Also includes awards granted to our Named Executive Officers under NU s long-term incentive programs, including dividend reinvestments, as follows:

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Name	2004 Program	2005 Program	2006 Program	2007 Program
Charles W. Shivery	5,896	15,266	27,892	32,597
David R. McHale	1,032	2,599	4,565	6,286
Leon J. Olivier	1,204	4,119	4,427	5,530
Gregory B. Butler	3,689	3,304	4,648	4,693
Raymond P. Necci	1,026	1,751	2,070	1,735

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 $27.12 per share, the closing price of NU common shares on February 22, 2008. This value includes the value of vested RSUs for which the distribution of common shares is currently deferred.

PENSION BENEFITS IN 2008

The Pension Benefits Table sets forth the estimated present value of accumulated retirement benefits that would be payable to each Named Executive Officer upon his or her retirement as of the first date upon which he or she 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 or her 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, Butler, and Necci (as to each of their respective make whole benefits), 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, 2008 assuming benefits would be paid in the form of a 50 percent spousal contingent annuitant option (the typical form of payment for the target benefit). 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 life annuity with a one-third spousal 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 life annuity with a one-third percent spousal contingent annuitant option (the typical form of payment under the Retirement Plan). None of Mr. Olivier s benefits will be provided under the Supplemental Plan. In addition, the present value of accrued benefits for any 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, Mr. Butler is eligible to receive unreduced benefits at age 62, and Mr. Necci is eligible to receive unreduced benefits immediately.

The limitations applicable to the Retirement Plan under the Internal Revenue Code as of December 31, 2008 were used to determine the benefits under each plan. The accrued benefits reflect actual compensation (both salary and incentives) earned during 2008. Under the terms of the Supplemental Plan, annual incentives earned for services provided in a plan year are deemed to have been paid ratably over that plan year. For example, the March 2009 payment pursuant to the 2008 annual incentive program was reflected in the 2008 plan compensation. NU determined the present value of the benefit at retirement age by using the discount rate of 6.89% under Statement of Financial Accounting Standards No. 87 for the 2008 fiscal year end measurement (as of December 31, 2008). This present value assumes no pre-retirement mortality, turnover or disability. However, for the postretirement period beginning at the retirement age, NU used the RP2000 Combined Healthy mortality table as published by the Society of Actuaries projected to 2009 with projection scale AA (same table used for financial reporting under FAS 87). Additional assumptions appear in the "Management s Discussion and Analysis and Results of Operations" in this Annual Report on Form 10-K.

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	6.6	198,961	
	Supplemental Plan	6.6	3,887,754	
	Other Special Benefit	9.6	1,862,537	
David R. McHale	Qualified Plan	27.3	421,008	
	Supplemental Plan	27.3	1,879,764	
Leon J. Olivier (2)	Qualified Plan	9.8	312,554	
	Supplemental Plan	7.3		
	Other Special Benefit	7.3	1,737,456	
	Other Special Benefit	31.3	1,205,507	105,966
Gregory B. Butler	Qualified Plan	12.0	199,430	
	Supplemental Plan	12.0	1,001,261	
Raymond P. Necci (3)	Qualified Plan	31.6	1,186,345	
	Supplemental Plan	31.6	1,478,386	
	Other Special Benefit	32.3	63,831	

(1)

Mr. Shivery’s actual service with us totaled 6.6 years at December 31, 2008. 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, 2008 was approximately $1,862,537.

(2)

Mr. Olivier was employed with Northeast Nuclear Energy Company, one of NU s subsidiaries, 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 his previous employer, Boston Edison Company (BECO), when calculating the value of his defined benefit pension, offset by the pension benefit provided by BECO. 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 from Entergy in September 2001. Mr. Olivier s current employment agreement provides for certain supplemental pension benefits in lieu of benefits under the Supplemental Plan, in order to provide a benefit similar to that provided by Entergy. Under this arrangement, if Mr. Olivier remains continuously employed by us until September 10, 2011 (or terminates his employment earlier with our 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 our 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. Because Mr. Olivier attained age 60 during 2008, amounts reported in the table assume the termination of his employment on December 31, 2008, and payment of the lump sum benefit of $2,050,000, offset by Retirement Plan benefits.

(3)

Mr. Necci s offer of employment provides for a special retirement benefit that recognizes an additional nine months of service, the value of which on December 31, 2008 was approximately $63,831.

NONQUALIFIED DEFERRED COMPENSATION IN 2008

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	32,022	2,159,552	(633,469)		3,957,405
David R. McHale		97,150	(46,015)	(41,979)	210,467
Leon J. Olivier	137,741	141,854	(181,878)	(16,772)	1,301,131
Gregory B. Butler		157,831	(87,703)		441,015
Raymond P. Necci	126,398	68,389	(113,179)		331,222

(1)

Reflects base salary deferrals by the Named Executive Officers under the Deferral Plan for 2008. 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 NU s 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, 2008 and posted on January 31, 2009, as reported in the All Other Compensation column of the Summary Compensation Table (Mr. Shivery: $25,122; Mr. Olivier: $9,629; and Mr. Necci: $2,670). The employer matching contribution is deemed to be invested in NU common shares but is paid in cash at the time of distribution. All other amounts relate to the value of NU 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 the vesting date (February 25, 2008). For more information, see the footnotes to the Options Exercised and Stock Vested Table.

(3)

Includes the total market value of Deferral Plan balances at December 31, 2008 plus the value of vested RSUs for which the distribution of common shares is currently deferred, based on $24.06 per share, the closing price of NU common shares on December 31, 2008.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE OF CONTROL

In the event of a change of control, the NEO s 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," either within 24 months following the change of control. 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 termination 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, a reduction in the compensation or benefits of the executive officer (a material reduction in base compensation for Mr. Olivier and Mr. Necci under the SSP, as defined below), 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 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% (75% for Mr. Olivier and Mr. Necci) of NU 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 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, 2008, 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 or she is entitled to receive certain amounts earned during his or her term of employment. Such amounts include:

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Vested RSUs;

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Amounts contributed under the Deferral Plan;

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Vested matching contributions under the Deferral Plan;

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Pay for unused vacation; and

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Amounts accrued and vested through the Retirement Plan and the 401k Plan.

I.

Post-Employment Compensation: Termination for Cause

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Butler ($)	Necci ($)
Incentive Programs					
Annual Incentives					
Performance Cash					
RSUs (1)	3,629,786	210,467	323,639	422,254	166,821
Pension and Deferred Compensation					
Retirement Plan (2)	180,964	224,712	200,398	124,624	1,186,345
Supplemental Plan					
Special Retirement Benefit			1,849,602		
Deferral Plan (3)	283,421		977,492	14,763	164,401
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	**4,094,171**	**435,179**	**3,351,131**	**561,641**	**1,517,567**

(1)

Represents values of all RSUs granted to the Named Executive Officers under NU’s long-term incentive programs that, as of the end of 2008, had been deferred upon vesting and remained deferred.

(2)

Represents the actuarial present values at the end of 2008 of benefits payable from the Retirement Plan to each Named Executive Officer at the earliest time that the payment of pension benefits can commence. The earliest benefit commencement times are different for each NEO based on plan provisions and age, as follows: Messrs. Shivery, Olivier, and Necci: immediately; Messrs. Butler and McHale: age 55. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008", above.

(3)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2008.

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II.

Post-Employment Compensation: Voluntary Termination

Type of Payment	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Necci ($)**
Incentive Programs					
Annual Incentives (1)	1,519,129	465,520	494,571	361,286	173,807
Performance Cash (2)	3,256,300	284,694	654,375	362,388	289,818
RSUs (3)	5,383,516	210,467	636,680	422,254	281,072
Pension and Deferred Compensation					
Retirement Plan (4)	180,964	224,712	200,398	124,624	1,186,345
Supplemental Plan (5)	4,426,647				1,478,386
Special Retirement Benefit (6)	2,099,936		1,849,602		63,832
Deferral Plan (7)	327,618		977,492	14,763	164,401
Other Benefits					
Health and Welfare Benefits (8)	105,879				
Perquisites					
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement					
Separation Payment for Liquidated Damages					
Total	**17,299,989**	**1,185,393**	**4,813,118**	**1,285,315**	**3,637,661**

(1)

Represents the actual 2008 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on Form 10-K.

(2)

Represents the actual 2006 - 2008 Performance Cash Program award for each Named Executive Officer. Also includes, for Messrs. Shivery, Olivier and Necci, prorated awards under the 2007 - 2009 and 2008 - 2010 Performance Cash Programs, because each of them would be considered to be a "retiree" under those programs. Amounts are prorated for time worked in each three-year performance period, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on Form 10-K.

(3)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs that, as of the end of 2008, had been deferred upon vesting and remained deferred, or that would vest upon voluntary termination of employment according to their program grant rules. Under the terms of each RSU grant, unvested RSUs that would have vested on February 25, 2009, would vest for Messrs. Shivery, Olivier, and Necci based on time worked since February 25, 2008, because each of them would be considered to be a "retiree" under those programs. The values were calculated by multiplying the number of RSUs by $24.06, the closing price of NU common shares on December 31, 2008.

(4)

Represents the actuarial present values at the end of 2008 of benefits payable from the Retirement Plan to each Named Executive Officer at the earliest time pension benefits can begin. The earliest benefit commencement times are different for each NEO based on plan provisions and age, as follows: Messrs. Shivery, Olivier, and Necci: immediately; Messrs. Butler and McHale: age 55. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(5)

Represents the actuarial present value at the end of 2008 of the benefit payable from the Supplemental Plan to Mr. Shivery upon termination. The benefit is payable as an annuity, and the present value was calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(6)

Represents the actuarial present values at the end of 2008 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon voluntary termination were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,050,000, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon voluntary termination. Pursuant to Mr. Necci s offer of employment, pension benefits available upon voluntary termination were calculated with the addition of nine months of service. Pension amounts reflected in the table are present values at the end of 2008 of benefits payable to each Named Executive Officer upon termination. Mr. Shivery s benefit would be paid as an annuity calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2008.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2008 of providing post-employment welfare benefits to Mr. Shivery beyond those benefits that would be provided to a nonexecutive employee upon involuntary termination. Mr. Shivery is entitled to receive retiree health benefits under his employment agreement. To the

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extent these benefits are provided in excess of those provided to employees in general, Mr. Shivery would receive payments to offset the taxes incurred on such benefits.

III.

Post-Employment Compensation: Involuntary Termination, Not for Cause

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Butler ($)	Necci ($)
Incentive Programs					
Annual Incentives (1)	1,519,129	465,520	494,571	361,286	173,807
Performance Cash (2)	3,256,300	284,694	654,375	362,388	289,818
RSUs (3)	7,643,654	554,902	636,680	702,008	281,072
Pension and Deferred Compensation					
Retirement Plan (4)	180,964	224,712	200,398	124,624	1,186,345
Supplemental Plan (5)	4,426,647				1,478,386
Special Retirement Benefit (6)	3,499,893	2,547,081	1,849,602	1,867,500	63,832
Deferral Plan (7)	327,618		977,492	14,763	164,401
Other Benefits					
Health and Welfare Benefits (8)	117,291	42,325	94,333	42,849	
Perquisites (9)	7,000	7,000		7,000	-
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement (10)	2,134,808	839,279		690,594	
Separation Payment for Liquidated Damages (11)	2,134,808	839,279		690,594	
Total	**25,248,112**	**5,804,792**	**4,907,451**	**4,863,606**	**3,637,661**

(1)

Represents the actual 2008 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on Form 10-K

(2)

Represents the actual 2006 - 2008 Performance Cash Program award. Also includes, for Messrs. Shivery, Olivier, and Necci, prorated awards under the 2007 - 2009 and 2008 - 2010 Performance Cash Programs, because each of them would be considered to be a "retiree" under those programs. Amounts are prorated for time worked in each three-year performance period, because each of them would be considered to be a "retiree" under those programs, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on Form 10-K.

(3)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs that, as of the end of 2008, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of each RSU grant, for the Named Executive Officers other than Mr. Shivery, unvested RSUs that would have vested on February 25, 2009, vest based on time worked since February 25, 2008, because each of them would be considered to be a "retiree" under those programs. The values were calculated by multiplying the number of RSUs by $24.06, the closing price of NU common shares on December 31, 2008.

(4)

Represents the actuarial present values at the end of 2008 of benefits payable from the Retirement Plan to each Named Executive Officer at the earliest time pension benefits can begin. The earliest benefit commencement times are different for each NEO based on plan provisions and age, as follows: Messrs. Shivery, Olivier, and Necci: immediately; Messrs. Butler and McHale: age 55. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(5)

Represents the actuarial present value at the end of 2008 of the benefit payable from the Supplemental Plan to Mr. Shivery upon termination. The benefit is payable as an annuity, and the present value was calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(6)

Represents the actuarial present values at the end of 2008 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreements with Messrs. McHale and Butler, pension benefits available upon an involuntary termination for other than cause were calculated with the addition of two years of age and service. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon an involuntary termination for other than cause were calculated with the addition of two years of age and five years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,050,000, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon an involuntary termination for other than cause. Pursuant to Mr. Necci s offer of employment, pension benefits available upon voluntary termination were calculated with the addition of nine months of service. Pension amounts reflected in the table are present values at the end of 2008 of benefits payable to each Named Executive Officer upon termination. Except for the benefit payable to Mr. Olivier, all benefits are annuities calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2008.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2008 of providing post-employment welfare benefits to the Named Executive Officers beyond those benefits that would be provided to a nonexecutive employee upon involuntary termination. Each of Messrs. Shivery, McHale and Butler is entitled to receive active health benefits and the cash value of company-paid active long-term disability and life insurance benefits for two years under the terms of his respective employment agreement. Each of Messrs. Shivery and Olivier is entitled to receive retiree health benefits under his respective employment agreement. For all health and welfare benefits provided in excess of those provided to employees in general, executives receive payments to offset the taxes incurred on such benefits. Six months of company-paid COBRA benefits are generally made available to all employees whose employment terminates involuntarily without cause. As a result, the amount reported in the table for Mr. Shivery represents (a) the value of 18 months of employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) the value of lifetime retiree health coverage, plus (c) tax gross-up payments thereon. The amounts reported in the table for Messrs. McHale and Butler represent (a) the value of 18 months of employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) tax gross-up payments thereon. The amount reported in the table for Mr. Olivier represents (a) the value of lifetime retiree health coverage, plus (b) tax gross-up payments thereon.

(9)

Represents the cost to NU of reimbursing fees for financial planning and tax preparation services to Messrs. Shivery, McHale, and Butler for two years.

(10)

Represents payments made as consideration for agreements by each of Messrs. Shivery, McHale, and Butler not to compete with the company following termination. Employment agreements with these Named Executive Officers provide for a lump-sum payment in an amount equal to their annual salary plus their annual incentive award at target. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

(11)

Represents severance payments to Messrs. Shivery, McHale, and Butler paid in addition to the non-compete agreement payments described in note (10). This payment is an amount equal to their actual base salary paid in 2008 plus annual incentive award at target. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

IV.

Post-Employment Compensation: Termination Upon Disability

Type of Payment	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Necci ($)**
Incentive Programs					
Annual Incentives (1)	1,519,129	465,520	494,571	361,286	173,807
Performance Cash (2)	3,256,300	634,694	654,375	657,939	289,818
RSUs (3)	5,383,516	554,902	636,680	702,008	281,072
Pension and Deferred Compensation					
Retirement Plan (4)	199,044	629,437	200,398	197,098	1,186,345
Supplemental Plan (5)	3,887,672	2,792,528		1,003,592	1,478,386
Special Retirement Benefit (6)	1,862,536		1,849,602		63,832
Deferral Plan (7)	327,618		977,492	18,762	164,401
Other Benefits					
Health and Welfare Benefits (8)	105,879		94,333		
Perquisites					
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement					
Separation Payment for Liquidated Damages					
Total	**16,541,694**	**5,077,081**	**4,907,451**	**2,940,685**	**3,637,661**

(1)

Represents the actual 2008 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on From 10-K.

(2)

Represents the actual 2006 - 2008 Performance Cash Program award determined as described in the "Compensation Discussion and Analysis" in this Annual report on Form 10-K, plus awards at target under the 2007 - 2009 Performance Cash Program and 2008 - 2010 Performance Cash Program prorated for time worked in each three-year performance period.

(3)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs that, as of the end of 2008, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of each RSU grant, unvested RSUs that would have vested on February 25, 2009, vest based on time worked since February 25, 2008. The values were calculated by multiplying the number of RSUs by $24.06, the closing price of NU common shares on December 31, 2008.

(4)

Under NU s 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

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when the LTD participant elects to commence pension payments, but not later than age 65. NU has assumed similar treatment in the development of the pension amounts reported in this table. For purposes of valuing the pension benefits, NU has assumed that each Named Executive Officer would remain on LTD until the executive s first unreduced combined pension benefit age. All payments would consist of life annuities calculated using the same assumptions detailed in the notes to the Pension Benefits Table. Therefore, the numbers shown represent the actuarial present values at the end of 2008 of benefits payable from the Retirement Plan to each Named Executive Officer, assuming termination of employment at the earliest unreduced benefit age for the combined total of all pension benefits. The earliest unreduced benefit ages are different for each NEO based on employment agreement provisions and years of service, as follows: Mr. Shivery: age 65; Mr. McHale: age 55; Mr. Butler: age 62; and Mr. Olivier and Mr. Necci: immediately. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(5)

Represents the actuarial present value at the end of 2008 of the benefit payable from the Supplemental Plan to each NEO other than Mr. Olivier under the assumptions discussed in note (4). The benefit is payable as an annuity, and the present value was calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(6)

Represents the actuarial present values at the end of 2008 of the amounts payable to the Named Executive Officers under the assumptions discussed in note (4), solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon disability termination were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,050,000, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon disability termination. Pursuant to Mr. Necci s employment offer, pension benefits available upon disability termination were calculated with the addition of nine months of service. Mr. Shivery s benefit would be paid as an annuity calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2008.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2008 of providing post-employment welfare benefits to Messrs. Shivery and Olivier beyond those benefits that would be provided to a nonexecutive employee upon disability termination. Each of Messrs. Shivery and Olivier is entitled to receive retiree health benefits under his respective employment agreement. To the extent these benefits are provided in excess of those provided to employees in general, Messrs. Shivery and Olivier would receive payments to offset the taxes incurred on such benefits.

V.

Post-Employment Compensation: Death

Type of Payment	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Necci ($)**
Incentive Programs					
Annual Incentives (1)	1,519,129	465,520	494,571	361,286	173,807
Performance Cash (2)	3,256,300	634,694	654,375	657,939	289,818
RSUs (3)	5,383,516	554,902	636,680	702,008	281,072
Pension and Deferred Compensation					
Retirement Plan (4)	91,191	1,000,786	172,523	122,432	1,108,068
Supplemental Plan (4)	2,230,676	2,584,178		759,256	1,380,840
Special Retirement Benefit (5)	1,058,200		1,877,477		59,620
Deferral Plan (6)	327,618		977,492	18,762	164,401
Other Benefits					
Health and Welfare Benefits (7)	59,985		39,525		
Perquisites					
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement					
Separation Payment for Liquidated Damages					
Total	**13,926,615**	**5,240,080**	**4,852,643**	**2,621,683**	**3,457,626**

(1)

Represents the actual 2008 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on Form 10-K.

(2)

Represents the actual 2006 - 2008 Performance Cash Program award determined as described in the "Compensation Discussion and Analysis" in this Annual report on Form 10-K, plus awards at target under the 2007 - 2009 Performance Cash Program and 2008 - 2010 Performance Cash Program prorated for time worked in each three-year performance period.

(3)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs that, as of the end of 2008, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of each RSU grant, unvested RSUs that would have vested on February 25, 2009, vest based on time worked since February 25, 2008. The values were calculated by multiplying the number of RSUs by $24.06, the closing price of NU common shares on December 31, 2008.

(4)

Represents the lump sum present value of pension payments from the Retirement Plan and the Supplemental Plan to the surviving spouse of each Named Executive Officer. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(5)

Represents the actuarial present values at the end of 2008 of the amounts payable to the surviving spouses of the Named Executive Officers, solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon death were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,050,000, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier s spouse upon death. Pursuant to Mr. Necci s employment offer, pension benefits available upon death were calculated with the addition of nine months of service. Pension amounts reflected in the table are present values at the end of 2008 of benefits payable immediately to each Named Executive Officer s surviving spouse. Mr. Shivery s benefit would be paid as an annuity calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(6)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2008.

(7)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2008 of providing post-employment welfare benefits to the surviving spouses of Messrs. Shivery and Olivier beyond those benefits that would be provided to a nonexecutive employee s spouse upon the employee s death. The surviving spouses of Messrs. Shivery and Olivier are entitled to receive retiree health benefits under the employment agreements. To the extent these benefits are taxable to the surviving spouses, they would receive payments to offset the taxes incurred on such benefits.

Payments Made Upon a Change of Control

The employment agreements with Messrs. Shivery, McHale, Olivier and Butler include change of control benefits. We have not entered into an employment agreement with Mr. Necci. Mr. Olivier and Mr. 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. 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 willful and continued failure to perform his duties after written notice, a violation of our Standards of Business Conduct or conviction of a felony), or by reason of death or disability), or if the executive officer terminates his or her 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 conditioned upon delivery of a binding release of all legal claims against the company:

.

A lump sum severance payment of two-times (one-time for Mr. Olivier and Mr. Necci) 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;

.

Active health benefits continuation, provided by NU for three years (two years for Mr. Olivier and Mr. Necci);

.

Retirement health coverage for Messrs. Shivery and Olivier, and for Messrs. McHale and Butler if the addition of three years of age and service would make the executive eligible under NU s retirement health plan;

.

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 Mr. Olivier and Mr. 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 this Annual Report on Form 10-K.

Pursuant to the terms of each of the 2007 2009 Performance Cash Program and 2008 2010 Performance Cash Program, following a change of control, performance cash awards would be vested, pro rata based on the number of days of employment during the performance period, and paid at target immediately, whether or not the executive s employment terminated, unless the Compensation Committee determined otherwise. Including the payment for the actual performance of the 2006 - 2008 Performance Cash Program that would have been made upon a December 31, 2008 change of control, these payments would total $4,791,300 for Mr. Shivery, $997,194 for Mr. McHale, $976,250 for Mr. Olivier, $958,335 for Mr. Butler, and $419,795 for Mr. Necci.

VI.

Post-Employment Compensation: Termination Following a Change of Control

Type of Payment	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Necci ($)**
Incentive Programs					
Annual Incentives (1)	1,519,129	465,520	494,571	361,286	173,807
Performance Cash (2)	4,791,300	997,194	976,250	958,335	419,795
RSUs (3)	7,643,654	1,047,053	998,163	1,065,239	425,417
Pension and Deferred Compensation					
Retirement Plan (4)	180,964	224,712	200,398	124,624	1,186,345
Supplemental Plan (5)	4,426,647				1,478,386
Special Retirement Benefit (6)	4,199,872	2,649,739	1,849,602	2,088,847	63,832
Deferral Plan (7)	327,618		977,492	18,762	164,401
Other Benefits					
Health and Welfare Benefits (8)	132,063	175,156	101,576	173,352	900
Perquisites (9)	8,500	8,500		8,500	
Separation Payments					
Excise Tax and Gross-Up (10)	3,489,202	2,500,264		1,891,228	
Separation Payment for Non-Compete Agreement (11)	2,134,808	839,279	909,087	690,594	478,500
Separation Payment for Liquidated Damages (12)	4,269,616	1,678,558	909,087	1,381,188	478,500
Total	**33,123,373**	**10,585,975**	**7,416,226**	**8,761,955**	**4,869,883**

(1)

Represents the actual 2008 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on Form 10-K.

(2)

Represents the actual 2006 - 2008 Performance Cash Program award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" in this Annual Report on Form 10-K, plus awards at target for each Named Executive Officer under the 2007 - 2009 Performance Cash Program and 2008 - 2010 Performance Cash Program.

(3)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2008, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. For Mr. Olivier, the value was reduced by $76,546 in accordance with provisions under the Special Severance Plan, which require a reduction in Change of Control payments if such reduction would eliminate the executive s excise tax but increase his net benefit. The values were calculated by multiplying the number of RSUs by $24.06, the closing price of NU common shares on December 31, 2008.

(4)

Represents the actuarial present values at the end of 2008 of benefits payable from the Retirement Plan to each Named Executive Officer at the earliest time pension benefits can begin. The earliest benefit commencement times are different for each NEO based on plan provisions and age, as follows: Messrs. Shivery, Olivier, and Necci: immediately; Messrs. Butler and McHale: age 55. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(5)

Represents the actuarial present value at the end of 2008 of the benefit payable from the Supplemental Plan to Mr. Shivery and Mr. Necci upon termination. The benefit is payable as an annuity, and the present value was calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(6)

Represents the actuarial present values at the end of 2008 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements, which are in addition to amounts payable by the

Retirement Plan or the Supplemental Plan. Pursuant to the employment agreements with Messrs. McHale and Butler, pension benefits available upon termination following a Change of Control were calculated with the addition of three years of age and service. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon termination following a Change of Control were calculated with the addition of three years of age and six years of service. Pursuant to the employment agreement with Mr. Butler, the value of the Supplemental Plan and Special Retirement Benefits will be paid as a single lump sum rather than as an annuity if his termination date occurs within two years following a change in control that qualifies under Section 1.409A of the Treasury Regulations. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,050,000, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon termination following a Change in Control. Pursuant to Mr. Necci s employment offer, pension benefits available upon termination following a Change of Control were calculated with the addition of nine months of age and six years of service. Pension amounts reflected in the table are present values at the end of 2008 of benefits payable to each Named Executive Officer upon termination Except for the benefits payable to Messrs. Butler and Olivier, all benefits are annuities calculated as described in Notes 1 and 2 to the Pension Benefits Table under "Pension Benefits in 2008" above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2008.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2008 of providing post-employment welfare benefits to the Named Executive Officers beyond those benefits that would be provided to a nonexecutive employee upon involuntary termination. Each of Messrs. Shivery, McHale and Butler is entitled to receive active health benefits and the cash value of company-paid active long-term disability and life insurance benefits for three years under the terms of his respective employment agreement. Each of Messrs. Shivery and Olivier is entitled to receive retiree health benefits under his respective employment agreement. Under his respective employment agreement, each of Messrs. McHale and Butler is entitled to receive retiree health benefits if adding three years of age and service would have made the executive eligible under the Retirement Plan. Mr. Olivier and Mr. Necci participate in the SSP and are eligible for two years of active health benefits continuation. For all health and welfare benefits provided in excess of those provided to employees in general, executives receive payments to offset the taxes incurred on such benefits. 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 for Messrs. Shivery, McHale, and Butler represent (a) the value of 30 months of employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) the value of lifetime retiree health coverage, plus (c) tax gross-up payments thereon. The amount reported in the table for Mr. Olivier represents (a) the value of 18 months of employer contributions toward active health benefits, plus (b) the value of lifetime retiree health coverage, plus (c) tax gross-up payments thereon. The amount reported in the table for Mr. Necci represents (a) the value of 18 months of employer contributions toward active health benefits, plus (b) tax gross-up payments thereon.

(9)

Represents the cost to NU of reimbursing fees for financial planning and tax preparation services to Messrs. Shivery, McHale, and Butler for three years.

(10)

Represents payments made to offset costs to Messrs. Shivery, McHale, and Butler associated with certain excise taxes under Section 280G of the Internal Revenue Code. Employees may be subject to certain excise taxes under Section 280G if they receive payments and benefits related to a termination following a Change of Control that exceed specified Internal Revenue Service limits. Employment agreements with each Named Executive Officer except Mr. Olivier and Mr. Necci provide for a grossed-up reimbursement of these excise taxes. The amounts in the table are based on the Section 280G excise tax rate of 20%, the statutory federal income tax withholding rate of 35%, the Connecticut state income tax rate of 5%, and the Medicare tax rate of 1.45%.

(11)

Represents payments made as consideration for each Named Executive Officer s agreement not to compete with the company following termination of employment. Agreements with each Named Executive Officer provide for a lump-sum payment in an amount equal to their annual salary plus their annual incentive award at target. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

(12)

Represents severance payments to each Named Executive Officer paid in addition to the non-compete agreement payments described in note (11). For Messrs. Shivery, McHale, and Butler, this payment is an amount equal to two-times actual base salary paid in 2008 plus annual incentive award at target. For Mr. Olivier and Mr. Necci, this payment is an amount equal to their actual base salary paid in 2008 plus their annual incentive award at target. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

Item 12.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

NU

In addition to the information below under "Securities Authorized for Issuance Under Equity Compensation Plans," 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 NU s definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about April 1, 2009.

PSNH and WMECO

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 17, 2009, the beneficial ownership of the equity securities of NU by (i) the Chief Executive Officer of CL&P and the 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 or executive officers of CL&P.

	Amount and Nature of Beneficial Ownership [1]				
	NU Common Shares	**Options [2]**	**Total**	**Percent of Class**	**Restricted Share Units [3]**
Leon J. Olivier, CEO of CL&P, Director [5]	18,421	-	18,421	*	55,623
David R. McHale, CFO, Director [5][6]	13,495	-	13,495	*	51,812
Gregory B. Butler, Senior Vice President and General Counsel [4][5][6]	27,902	-	27,902	*	51,049
Raymond P. Necci, President, Chief Operating Officer, Director [5][6]	19,503	-	19,503	*	20,719
Charles W. Shivery, Director [5][7]	48,264	29,024	77,288	*	356,645
				*	
All directors and Executive Officers as a Group (8 persons)	140,781	51,924	192,705	*	584,524

*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 17, 2009.

(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 spouse with whom he shares voting and investment power.

(5)

Includes common shares held in the 401k Plan in the employee stock ownership plan account over which the holder has sole voting and no investment power (Mr. Butler: 2,643 shares; Mr. McHale: 3,396 shares; Mr. Necci: 5,382 shares; Mr. Olivier: 1,366 shares; and Mr. Shivery: 1,509 shares).

(6)

Includes common shares held as units in the 401k Plan invested in the NU Common Shares Fund over which the holder has sole voting and investment power (Mr. Butler: 409 shares, Mr. McHale: 1,566 shares and Mr. Necci: 237 shares).

(7)

Includes 1,500 common shares owned jointly by Mr. Shivery and his spouse with whom he shares voting and investment power.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth the number of NU common shares issuable under NU equity compensation plans, as well as their weighted exercise price, in accordance with the rules of the SEC, at December 31, 2008:

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	1,165,067 [(a)]	$18.83 [(b)]	3,715,729 [(c)]
Equity compensation plans not approved by security holders (d)	-	-	-
Total	1,165,067	$18.83	3,715,729

(a)

Includes 320,920 common shares to be issued upon exercise of options, and 844,147 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 1,010,114 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 NU s shareholders.

Item 13.

Certain Relationships and Related Transactions, and Director Independence

NU

Incorporated herein by reference is the information contained in the sections captioned "Trustee Independence" and "Certain Relationships and Related Transactions" of NU s definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about April 1, 2009.

PSNH and WMECO

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**.**

CL&P

NU s Code of Ethics for Senior Financial Officers applies to the Senior Financial Officers (Chief Executive Officer, Chief Financial Officer and Controller) of CL&P and certain other NU subsidiaries. Under the Code, one s position as a Senior Financial Officer in the company may not be used to improperly benefit such officer or his or her family or friends. Under the Code, specific activities that may be considered conflicts of interest include, but are not limited to, directly or indirectly acquiring or retaining a significant financial interest in an organization that is a customer, vendor or competitor, or that seeks to do business with the company; serving, without proper safeguards, as an officer or director of, or working or rendering services for an organization that is a customer, vendor or competitor, or that seeks to do business with the company. Waivers of the provisions of the Code of Ethics must be approved by NU s Board of Trustees. Any such Waivers will be disclosed pursuant to legal requirements.

NU s Standards of Business Conduct (SBC), which applies to all Trustees, directors, officers and employees of NU and its subsidiaries, including CL&P, contains a Conflict of Interest Policy which requires all such individuals to disclose any potential conflicts of interest. Such individuals are expected to discuss their particular situations with management to ensure appropriate steps are in place to avoid a conflict of interest. All disclosures must be reviewed and approved by management to ensure a particular situation does not adversely impact the individual s primary job and role.

In addition, NU s Board of Trustees adopted a Related Party Transactions Policy on December 11, 2007. The Policy is administered by the Corporate Governance Committee of the Board. The Policy generally defines a "Related Party Transaction" as any transaction or series of transactions in which (i) Northeast Utilities or a subsidiary is a participant, (ii) the aggregate amount involved exceeds $120,000 and (iii) any "Related Party" has a direct or indirect material interest. A "Related Party" is defined as any Trustee or nominee for Trustee, any executive officer, any shareholder owning more than 5% of our total outstanding shares, and any immediate family member of any such person. Management submits to the Corporate Governance Committee for consideration any Related Party Transaction into which NU proposes to enter. The Corporate Governance Committee recommends to the Board of Trustees for approval only those transactions that are in NU s best interests. If management causes the company to enter into a Related Party Transaction prior to approval by the Committee, the transaction will be subject to ratification by the Board of Trustees. If the Board determines not to ratify the transaction, then management will make all reasonable efforts to cancel or annul such transaction.

The Directors of CL&P are employees of CL&P and/or other subsidiaries of NU and thus are not considered independent.

Item 14.

Principal Accountant Fees and Services

NU

Incorporated herein by references is the information contained in the section "Relationship with Independent Auditors" of NU s definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about April 1, 2009.

CL&P, PSNH and WMECO

Pre-Approval of Services Provided by Principal Auditors

None of CL&P, PSNH or 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. NU s 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 Audit Committee Chair and/or Vice Chair provided that such offices are held by Trustees who are "independent" within the meaning of the Sarbanes-Oxley Act of 2002 and that all such pre-approvals are presented to the Audit Committee at the next regularly scheduled meeting of the Committee.

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

Fees Paid to Principal Auditor

NU and its subsidiaries paid Deloitte & Touche LLP fees aggregating $3,053,830 and $3,108,754 for the years ended December 31, 2008 and 2007, respectively, comprised of the following:

1.

Audit Fees

The aggregate fees billed to NU and its 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, 2008 and 2007 totaled $2,914,830 and $2,789,900, respectively. The audit fees were incurred for audits of NU s annual consolidated financial statements and those of its subsidiaries, reviews of financial statements included in NU s Quarterly Reports on Form 10-Q and those of its 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, 2008 and 2007, as well as auditing the implementation of new accounting standards and the accounting for new contracts.

2.

Audit Related Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for audit related services rendered for the years ended December 31, 2008 and 2007 totaled $117,500 and $260,000, respectively, primarily related to the examination of management s assertions about the securitization subsidiaries of CL&P, PSNH and WMECO. The 2007 fees also included the audits of NU s various employee benefit plans.

3.

Tax Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for tax services for the years ended December 31, 2008 and 2007 totaled $20,000 and $57,354, 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 NU and its subsidiaries by the Deloitte Entities for services other than the services described above totaled $1,500 for each of the years ended December 31, 2008 and 2007, consisting of a license fee for access to an accounting research database.

The Audit Committee of the NU Board of Trustees (Audit Committee) pre-approves all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed for NU and its subsidiaries by the 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 Audit Committee prior to the completion of the audit. The 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 Audit Committee at its next scheduled meeting. During 2008, the only audit related services provided by the Deloitte Entities that were not pre-approved by the Audit Committee were de minimis services for work paper review and other work related to transitioning the audit of our employee benefit plans to a different firm, for which the Deloitte Entities received a fee of $2,500. Also not pre-approved were services provided in rendering an agreed upon procedures certificate letter as required by a bond indenture, 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 financial statement audit. The Deloitte Entities did not provide any other services that were not pre-approved by the Audit Committee.

The 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 NU and its subsidiaries in all respects.

Part IV

Item 15.

Exhibits and Financial Statement Schedules

(a)	1.	Financial Statements:		
			The consolidated Financial Statements of each of NU, CL&P, PSNH and WMECO, the accompanying combined Notes to the Financial Statements, and the Report of Independent Registered Public Accounting Firm for each of NU, CL&P, PSNH and WMECO.	FS-1
	2.	Schedules		
		I.	Financial Information of Registrant: Northeast Utilities (Parent) Balance Sheets at December 31, 2008 and 2007	S-1
			Northeast Utilities (Parent) Statements of Income for the Years Ended December 31, 2008, 2007 and 2006	S-2
			Northeast Utilities (Parent) Statements of Cash Flows for the Years Ended December 31, 2008, 2007 and 2006	S-3
		II.	Valuation and Qualifying Accounts and Reserves for NU, CL&P, PSNH and WMECO for 2008, 2007 and 2006	S-4
			All other schedules of the companies for which inclusion is required in the applicable regulations of the SEC are permitted to be omitted under the related instructions or are not applicable, and therefore have been omitted.	
	3.		Exhibit Index	E-1

NORTHEAST UTILITIES

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/	Date
	Charles W. Shivery	
	Charles W. Shivery	
	Chairman of the Board,	February 27, 2009
	President and Chief Executive Officer	
	(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 of the Board, President and Chief Executive Officer, and a Trustee (Principal Executive Officer)	February 27, 2009
/s/ David R. McHale David R. McHale	Executive Vice President and Chief Financial Officer	February 27, 2009

	(Principal Financial Officer)	
/s/	Vice President - Accounting and Controller	February 27, 2009
Shirley M. Payne Shirley M. Payne		
/s/	Trustee	February 27, 2009
Richard H. Booth Richard H. Booth		
/s/	Trustee	February 27, 2009
John S. Clarkeson John S. Clarkeson		
/s/	Trustee	February 27, 2009
Cotton M. Cleveland Cotton M. Cleveland		
/s/	Trustee	February 27, 2009
Sanford Cloud, Jr. Sanford Cloud, Jr.		
/s/	Trustee	February 27, 2009
James F. Cordes James F. Cordes		
/s/	Trustee	February 27, 2009
E. Gail de Planque E. Gail de Planque		
/s/	Trustee	February 27, 2009
John G. Graham John G. Graham		
/s/	Trustee	February 27, 2009

Elizabeth T. Kennan
Elizabeth T. Kennan

/s/	Trustee	February 27, 2009
Kenneth R. Leibler Kenneth R. Leibler		
/s/	Trustee	February 27, 2009
Robert E. Patricelli Robert E. Patricelli		
/s/	Trustee	February 27, 2009
John F. Swope John F. Swope		

THE CONNECTICUT LIGHT AND POWER COMPANY

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/	Date
	Leon J. Olivier	
	Leon J. Olivier	
	Chief Executive Officer	February 27, 2009
	(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/	Chairman and a Director	February 27, 2009
Charles W. Shivery		
Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 27, 2009
Leon J. Olivier		
Leon J. Olivier	(Principal Executive Officer)	

/s/ Raymond P. Necci Raymond P. Necci	President and Chief Operating Officer and a Director	February 27, 2009
/s/ David R. McHale David R. McHale	Executive Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 27, 2009
/s/ Shirley M. Payne Shirley M. Payne	Vice President - Accounting and Controller	February 27, 2009

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

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/	Date
	Leon J. Olivier	
	Leon J. Olivier	
	Chief Executive Officer	February 27, 2009
	(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/	Chairman and a Director	February 27, 2009
Charles W. Shivery		
Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 27, 2009
Leon J. Olivier		

Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 27, 2009
Gary A. Long		
Gary A. Long	and a Director	
/s/	Executive Vice President and Chief Financial	February 27, 2009
David R. McHale		
David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Vice President - Accounting and Controller	February 27, 2009
Shirley M. Payne		
Shirley M. Payne		

WESTERN MASSACHUSETTS ELECTRIC COMPANY

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/	Date
	Leon J. Olivier	
	Leon J. Olivier	
	Chief Executive Officer	February 27, 2009
	(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/	Chairman and a Director	February 27, 2009
Charles W. Shivery		
Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 27, 2009
Leon J. Olivier		
Leon J. Olivier	(Principal Executive Officer)	

/s/	President and Chief Operating Officer	February 27, 2009
Peter J. Clarke		
Peter J. Clarke	and a Director	
/s/	Executive Vice President and Chief Financial	February 27, 2009
David R. McHale		
David R. McHale	Officer and a Director	
	(Principal Financial Officer)	
/s/	Vice President - Accounting and Controller	February 27, 2009
Shirley M. Payne		
Shirley M. Payne		

Company Report on Internal Controls Over Financial Reporting

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

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company s internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of the principal executive officer and principal financial officer, NU conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting were effective as of December 31, 2008.

February 27, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Northeast Utilities and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, common shareholders equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the consolidated financial statement schedules listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Company Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 4, the Company adopted Financial Accounting Standards Board Statement No. 157, *Fair Value Measurements*, as of January 1, 2008.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut

February 27, 2009

NORTHEAST UTILITIES AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	At December 31, 2008	2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 89,816	$ 15,104
Investments in securitizable assets (Note 1L)	-	308,182
Receivables, less provision for uncollectible accounts of $43,275 in 2008 and $25,529 in 2007	698,755	401,283
Unbilled revenues	218,440	101,860
Taxes receivable	-	13,850
Fuel, materials and supplies	300,049	210,850
Marketable securities - current	78,452	70,816
Derivative assets - current	31,373	105,517
Prepayments and other	88,679	58,794
	1,505,564	1,286,256
Property, Plant and Equipment:		
Electric utility	9,219,351	7,594,606
Gas utility	1,043,687	977,290
Other	290,156	310,535
	10,553,194	8,882,431
Less: Accumulated depreciation: $2,610,479 for electric and gas utility and $159,639 for other in 2008; $2,483,570 for electric and gas utility and $178,193 for other in 2007	2,770,118	2,661,763
	7,783,076	6,220,668
Construction work in progress	424,800	1,009,277

	8,207,876	7,229,945
Deferred Debits and Other Assets:		
Regulatory assets	3,502,606	2,057,083
Goodwill	287,591	287,591
Prepaid pension	-	202,512
Marketable securities - long-term	30,757	53,281
Derivative assets - long-term	241,814	298,001
Other	212,272	167,153
	4,275,040	3,065,621
Total Assets	$ 13,988,480	$ 11,581,822

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, 2008	2007
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 618,897	$ 79,000
Long-term debt - current portion	54,286	154,286
Accounts payable	678,614	598,546
Accrued taxes	12,527	-
Accrued interest	69,818	56,592
Derivative liabilities - current	100,919	71,601
Other	168,401	246,125
	1,703,462	1,206,150
Rate Reduction Bonds	686,511	917,436
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,223,461	1,067,490
Accumulated deferred investment tax credits	25,371	28,845
Deferred contractual obligations	193,016	222,908
Regulatory liabilities	592,540	851,780
Derivative liabilities - long-term	912,426	208,461
Accrued pension	740,930	-
Accrued postretirement benefits	240,371	181,507
Other	430,718	383,611
	4,358,833	2,944,602
Capitalization:		
Long-Term Debt	4,103,162	3,483,599
Preferred Stock of Subsidiary - Non-Redeemable	116,200	116,200

Common Shareholders' Equity:		
Common shares, $5 par value - authorized 225,000,000 shares; 176,212,275 shares issued and 155,834,361 shares outstanding in 2008 and 175,924,694 shares issued and 155,079,770 shares outstanding in 2007	881,061	879,623
Capital surplus, paid in	1,475,006	1,465,946
Deferred contribution plan - employee stock ownership plan	(15,481)	(26,352)
Retained earnings	1,078,594	946,792
Accumulated other comprehensive (loss)/income	(37,265)	9,359
Treasury stock, 19,708,136 shares in 2008 and 19,705,545 shares in 2007	(361,603)	(361,533)
Common Shareholders' Equity	3,020,312	2,913,835
Total Capitalization	7,239,674	6,513,634
Commitments and Contingencies (Note 7)		
Total Liabilities and Capitalization	$ 13,988,480	$ 11,581,822

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars, except share information)	For the Years Ended December 31, 2008	2007	2006
Operating Revenues	$ 5,800,095	$ 5,822,226	$ 6,877,687
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	2,996,180	3,350,673	4,630,798
Other	1,021,704	961,285	1,121,534
Maintenance	254,038	211,589	193,706
Depreciation	278,588	265,297	240,559
Amortization of regulatory assets, net	186,396	40,674	16,292
Amortization of rate reduction bonds	204,859	201,039	188,247
Taxes other than income taxes	267,565	252,188	250,580
Total operating expenses	5,209,330	5,282,745	6,641,716
Operating Income	590,765	539,481	235,971
Interest Expense:			
Interest on long-term debt	193,883	162,841	141,579
Interest on rate reduction bonds	50,231	61,580	74,242
Other interest	25,031	15,824	22,375
Interest expense, net	269,145	240,245	238,196
Other Income, Net	50,428	61,639	64,394
Income from Continuing Operations Before			
Income Tax Expense/(Benefit)	372,048	360,875	62,169
Income Tax Expense/(Benefit)	105,661	109,420	(76,326)
Income from Continuing Operations Before			

Preferred Dividends of Subsidiary	266,387	251,455	138,495
Preferred Dividends of Subsidiary	5,559	5,559	5,559
Income from Continuing Operations	260,828	245,896	132,936
Discontinued Operations (Note 14):			
Income from Discontinued Operations	-	435	31,321
Gains from Sale/Disposition of Discontinued Operations	-	2,054	504,314
Income Tax Expense	-	1,902	197,993
Income from Discontinued Operations	-	587	337,642
Net Income	$ 260,828	$ 246,483	$ 470,578
Basic Earnings Per Common Share:			
Income from Continuing Operations	$ 1.68	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	2.20
Basic Earnings Per Common Share	$ 1.68	$ 1.59	$ 3.06
Fully Diluted Earnings Per Common Share:			
Income from Continuing Operations	$ 1.67	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	2.19
Fully Diluted Earnings Per Common Share	$ 1.67	$ 1.59	$ 3.05
Basic Common Shares Outstanding (weighted average)	155,531,846	154,759,727	153,767,527
Fully Diluted Common Shares Outstanding (weighted average)	155,999,240	155,304,361	154,146,669

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(Thousands of Dollars, except share information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Deferred Contribution Plan - ESOP	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total
Balance as of January 1, 2006	153,225,892	$ 874,489	$1,437,561	$(46,884)	$ 504,301	$ 19,987	$(360,210)	$2,429,244
Net income for 2006					470,578			470,578
Dividends on common shares - $0.725 per share					(112,219)			(112,219)
Issuance of common shares, $5 par value	522,535	2,612	6,882					9,494
Allocation of benefits - ESOP	523,452		(618)	12,118				11,500
Change in restricted shares, net	(38,738)		4,293				(690)	3,603
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying			1,112					1,112

dispositions								
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
Net income for 2008					260,828			260,828
Dividends on common shares - $0.825 per share					(129,026)			(129,026)
Issuance of common shares, $5 par value	287,581	1,438	4,086					5,524
Allocation of benefits - ESOP	469,601		865	10,871				11,736
Change in restricted shares, net	(2,591)		2,436				(70)	2,366
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			1,622					1,622
Capital stock expenses, net			51					51
Other comprehensive loss						(46,624)		(46,624)
Balance as of								

December 31, 2008	155,834,361	$ 881,061	$1,475,006	$(15,481)	$1,078,594		$ (37,265)	$(361,603)	$3,020,312

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2008	2007	2006
Operating Activities:			
Net income	$ 260,828	$ 246,483	$ 470,578
Adjustments to reconcile to net cash flows			
provided by operating activities:			
Pre-tax gains from sale/disposition of discontinued operations	-	(2,054)	(504,314)
Bad debt expense	28,573	29,140	29,366
Depreciation	278,588	265,297	243,822
Deferred income taxes	86,810	6,933	(204,212)
Amortization of investment tax credits	(3,474)	(3,583)	(3,673)
Pension and PBOP expense and contributions, net of capitalized portion	(3,839)	10,865	38,994
Stock-based compensation expense	13,518	13,855	14,718
Allowance for equity funds used during construction	(29,028)	(17,417)	(13,573)
Impairment of marketable securities	17,399	2,539	-
(Deferral)/amortization of recoverable energy costs	(10,590)	11,715	15,609
Amortization of rate reduction bonds	204,859	201,039	188,247
Amortization of regulatory assets, net	186,396	40,674	16,292
Regulatory (refunds and underrecoveries)/overrecoveries	(174,662)	37,010	(96,560)
Derivative assets and liabilities	(37,052)	(43,808)	(90,867)
Deferred contractual obligations	(32,326)	(41,950)	(90,671)
(Increase)/decrease in other deferred debits	(16,873)	(5,026)	2,837
Increase/(decrease) in other deferred credits	4,735	(8,784)	(10,451)
Other adjustments	(5,738)	(4,464)	22,921

Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(141,879)	(65,381)	605,366
Fuel, materials and supplies	(74,531)	(33,727)	16,718
Investments in securitizable assets	(25,787)	33,531	(158,651)
Other current assets	(4,677)	3,878	58,350
Accounts payable	72,791	(49,554)	(399,386)
Counterparty deposits and margin special deposits	(7,474)	29,505	26,469
Taxes receivable/accrued	63,251	(392,611)	271,477
Other current liabilities	(400)	(15,670)	(42,332)
Net cash flows provided by operating activities	649,418	248,435	407,074
Investing Activities:			
Investments in property and plant	(1,255,407)	(1,114,824)	(872,181)
Net proceeds from sales of competitive businesses	-	-	1,053,099
Cash payments related to the sale of competitive businesses	-	(16,648)	(32,359)
Proceeds from sales of marketable securities	259,361	254,832	193,459
Purchases of marketable securities	(262,357)	(261,777)	(193,917)
Rate reduction bond escrow and other deposits	1,686	63,722	(50,686)
Other investing activities	3,360	7,229	19,649
Net cash flows (used in)/provided by investing activities	(1,253,357)	(1,067,466)	117,064
Financing Activities:			
Issuance of common shares related to share-based compensation	5,524	9,056	9,494
Cash dividends on common shares	(129,077)	(120,988)	(112,745)
Increase/(decrease) in short-term debt	539,897	79,000	(32,000)
Issuance of long-term debt	760,000	655,000	250,000
Reacquisition and retirements of long-term debt	(261,286)	(4,877)	(28,843)
Retirements of rate reduction bonds	(230,925)	(259,722)	(173,344)
Other financing activities	(5,482)	(5,245)	(571)
Net cash flows provided by/(used in) financing activities	678,651	352,224	(88,009)
Net increase/(decrease) in cash and cash equivalents	74,712	(466,807)	436,129
Cash and cash equivalents - beginning of year	15,104	481,911	45,782
Cash and cash equivalents - end of year	$ 89,816	$ 15,104	$ 481,911

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION

		At December 31,	
(Thousands of Dollars)		2008	2007
Common Shareholders Equity		$ 3,020,312	$ 2,913,835
Preferred Stock:			
CL&P Preferred Stock Not Subject to Mandatory Redemption -			
$50 par value - authorized 9,000,000 shares in 2008 and 2007;			
2,324,000 shares outstanding in 2008 and 2007;			
Dividend rates of $1.90 to $3.28;			
Current redemption prices of $50.50 to $54.00		116,200	116,200
Long-Term Debt:			
First Mortgage Bonds:			
Final Maturity	Interest Rates		
2009-2012	6.20% to 7.19%	67,143	71,429
2014-2018	4.80% to 6.90%	1,205,000	695,000
2019-2024	5.26% to 8.48%	209,845	209,845
2026-2037	5.35% to 6.375%	830,000	830,000
Total First Mortgage Bonds		2,311,988	1,806,274
Other Long-Term Debt:			
Pollution Control Notes:			
2016-2018	5.90%	25,400	25,400
2021-2022	Variable Rate and 4.75% to 6.00%	428,285	428,285
2028	5.85% to 5.95%	369,300	369,300
2031	3.35% and Variable Rate in 2008; 3.35% in 2007	62,000	62,000
Other:			
2008-2009	Variable Rate and 3.30%	-	195,000
2012-2015	5.00% to 7.25%	618,000	368,000
2034-2037	5.90% to 6.70%	90,000	90,000
Total Pollution Control Notes and Other		1,592,985	1,537,985
Total First Mortgage Bonds, Pollution Control Notes and Other		3,904,973	3,344,259

Fees and interest due for spent nuclear fuel disposal costs	298,555	294,305
Change in fair value resulting from interest rate hedge instrument	20,828	4,172
Unamortized premium and discount, net	(4,908)	(4,851)
Reacquisition of Pollution Control Notes	(62,000)	-
Total Long-Term Debt	4,157,448	3,637,885
Less: Amounts due within one year	54,286	154,286
Long-Term Debt	4,103,162	3,483,599
Total Capitalization	$ 7,239,674	$ 6,513,634

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. This combined annual report does not include an attestation report from Deloitte & Touche LLP regarding the internal controls over financial reporting for CL&P. Management s report on behalf of CL&P was not subject to attestation pursuant to temporary rules of the Securities and Exchange Commission that permit this company to provide only management s report in this combined 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 the 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 internal controls over financial reporting were effective as of December 31, 2008.

February 27, 2009

Report of Independent Registered Public Accounting Firm

To the Board of 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, 2008 and 2007, 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, 2008. Our audits also included the consolidated financial statement schedules listed in the Index at Item 15. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules 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, 2008 and 2007, 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. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 4, the Company adopted Financial Accounting Standards Board Statement No. 157, *Fair Value Measurement*, as of January 1, 2008.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut

February 27, 2009

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	At December 31,	
(Thousands of Dollars)	2008	2007
ASSETS		
Current Assets:		
Cash	$ -	$ 538
Investments in securitizable assets (Note 1L)	-	308,182
Receivables, less provision for uncollectible accounts of $23,956 in 2008 and $7,874 in 2007	416,304	118,342
Accounts receivable from affiliated companies	11,215	3,339
Unbilled revenues	127,844	8,225
Taxes receivable	-	16,245
Materials and supplies	70,676	55,477
Derivative assets - current	30,478	57,003
Prepayments and other	15,685	17,387
	672,202	584,738
Property, Plant and Equipment:		
Electric utility	6,244,705	4,899,075
Less: Accumulated depreciation	1,346,062	1,279,697
	4,898,643	3,619,378
Construction work in progress	190,481	782,468
	5,089,124	4,401,846
Deferred Debits and Other Assets:		
Regulatory assets	2,274,088	1,329,963

Prepaid pension	-	334,786
Derivative assets - long-term	215,288	278,726
Other	85,416	88,040
	2,574,792	2,031,515
Total Assets	$ 8,336,118	$ 7,018,099

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,	
(Thousands of Dollars)	2008	2007
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 187,973	$ -
Notes payable to affiliated companies	102,725	38,825
Accounts payable	353,584	368,356
Accounts payable to affiliated companies	57,053	53,096
Accrued taxes	24,839	-
Accrued interest	37,567	29,532
Derivative liabilities - current	8,873	4,234
Other	92,444	107,940
	865,058	601,983
Rate Reduction Bonds	378,195	548,686
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes - long-term	811,405	698,789
Accumulated deferred investment tax credits	18,805	21,412
Deferred contractual obligations	132,687	152,735
Regulatory liabilities	363,547	601,455
Derivative liabilities - long-term	848,106	135,991
Accrued pension	89,254	-
Accrued postretirement benefits	98,587	78,587
Other	215,620	191,464
	2,578,011	1,880,433
Capitalization:		
Long-Term Debt	2,270,414	2,028,546

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 2008 and 2007		60,352		60,352
Capital surplus, paid in		1,454,198		1,243,940
Retained earnings		617,276		538,138
Accumulated other comprehensive loss		(3,586)		(179)
Common Stockholder's Equity		2,128,240		1,842,251
Total Capitalization		4,514,854		3,986,997
Commitments and Contingencies (Note 7)				
Total Liabilities and Capitalization	$	8,336,118	$	7,018,099

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,		
(Thousands of Dollars)	2008	2007	2006
Operating Revenues	$ 3,558,361	$ 3,681,817	$ 3,979,811
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	1,845,367	2,277,054	2,603,882
Other	557,565	535,750	614,372
Maintenance	130,365	108,001	101,443
Depreciation	162,636	152,005	147,460
Amortization of regulatory assets/(liabilities), net	164,246	20,593	(11,251)
Amortization of rate reduction bonds	145,590	135,929	126,909
Taxes other than income taxes	179,201	167,943	160,926
Total operating expenses	3,184,970	3,397,275	3,743,741
Operating Income	373,391	284,542	236,070
Interest Expense:			
Interest on long-term debt	104,954	84,292	64,873
Interest on rate reduction bonds	29,129	37,728	46,692
Other interest	12,163	16,413	6,281
Interest expense, net	146,246	138,433	117,846
Other Income, Net	41,865	39,808	37,822
Income Before Income Tax Expense/(Benefit)	269,010	185,917	156,046
Income Tax Expense/(Benefit)	77,852	52,353	(43,961)
Net Income	$ 191,158	$ 133,564	$ 200,007

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME			
Net Income	$ 191,158	$ 133,564	$ 200,007
Other comprehensive (loss)/income, net of tax:			
Qualified cash flow hedging instruments	(3,348)	(4,814)	4,537
Changes in unrealized gains on securities	(59)	(5)	17
Minimum SERP liability	-	-	364
Other comprehensive (loss)/income, net of tax	(3,407)	(4,819)	4,918
Comprehensive Income	$ 187,751	$ 128,745	$ 204,925

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

THE CONNECTICUT LIGHT AND POWER COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, except share information)	Common Stock Shares	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance at January 1, 2006	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 contributions from NU parent			60,755			60,755
Other comprehensive income					4,918	4,918
Balance at December 31,	6,035,205	60,352	672,693	513,344	4,640	1,251,029

2006						
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 contributions 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
Net income for 2008				191,158		191,158
Dividends on preferred stock				(5,559)		(5,559)
Dividends on common stock				(106,461)		(106,461)
Allocation of benefits - ESOP			207			207
Capital stock expenses, net			51			51
Capital contributions from NU parent			210,000			210,000
Other comprehensive loss					(3,407)	(3,407)
Balance at December 31,	6,035,205	$ 60,352	$ 1,454,198	$ 617,276	$ (3,586)	$ 2,128,240

2008

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,		
(Thousands of Dollars)	2008	2007	2006
Operating Activities:			
Net income	$ 191,158	$ 133,564	$ 200,007
Adjustments to reconcile to net cash flows provided by operating activities:			
Depreciation	162,636	152,005	147,460
Deferred income taxes	47,653	28,725	(154,260)
Amortization of investment tax credits	(2,607)	(2,607)	(2,607)
Bad debt expense	5,951	18,121	13,582
Pension and PBOP (income)/expense and contributions, net of capitalized portion	(19,257)	(10,334)	351
Allowance for equity funds used during construction	(23,212)	(14,230)	(7,631)
Amortization of recoverable energy costs	-	3,440	3,839
Amortization of rate reduction bonds	145,590	135,929	126,909
Amortization of regulatory assets/(liabilities), net	164,246	20,593	(11,251)
Regulatory (refunds and underrecoveries)/overrecoveries	(153,843)	4,441	(80,888)
Net settlement of cash flow hedge instruments	(3,890)	(10,445)	7,818
Deferred contractual obligations	(21,526)	(28,019)	(61,273)
(Increase)/decrease in other deferred debits	(7,142)	89	7,910
Increase/(decrease) in other deferred credits	5,574	(928)	(717)
Other adjustments	2,133	(1,093)	3,015
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(125,241)	(44,025)	22,924
Materials and supplies	(15,204)	(16,030)	(6,518)
Investments in securitizable assets	(25,787)	33,531	(158,254)
Other current assets	1,431	(3,208)	6,786

Accounts payable	28,772	3,457	56,628
Taxes receivable/accrued	60,864	(216,714)	126,116
Other current liabilities	19,454	13,471	11,421
Net cash flows provided by operating activities	437,753	199,733	251,367
Investing Activities:			
Investments in property and plant	(849,549)	(826,248)	(567,151)
Proceeds from sales of marketable securities	3,139	2,015	2,210
Purchases of marketable securities	(3,214)	(2,154)	(2,369)
Rate reduction bond escrow and other deposits	(2,991)	56,872	(51,985)
Other investing activities	623	3,923	12,032
Net cash flows used in investing activities	(851,992)	(765,592)	(607,263)
Financing Activities:			
Cash dividends on common stock	(106,461)	(79,181)	(63,732)
Cash dividends on preferred stock	(5,559)	(5,559)	(5,559)
Increase in short-term debt	187,973	-	-
Increase/(decrease) in NU Money Pool borrowings	63,900	(220,100)	232,100
Capital contributions from NU parent	210,000	570,661	60,756
Issuance of long-term debt	300,000	500,000	250,000
Reacquisition of long-term debt	(62,000)	-	-
Retirements of rate reduction bonds	(170,491)	(195,213)	(112,580)
Other financing activities	(3,661)	(7,521)	(4,080)
Net cash flows provided by financing activities	413,701	563,087	356,905
Net (decrease)/increase in cash	(538)	(2,772)	1,009
Cash - beginning of year	538	3,310	2,301
Cash - end of year	$ -	$ 538	$ 3,310
Supplemental Cash Flow Information:			
Cash paid/(received) during the year for:			
Interest, net of amounts capitalized	$ 145,521	$ 156,445	$ 117,856
Income taxes	$ (20,617)	$ 241,219	$ (16,364)
Non-cash investing activities:			
Capital expenditures incurred but not paid	$ 76,110	$ 126,148	$ 76,248

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

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. This combined annual report does not include an attestation report from Deloitte & Touche LLP regarding the internal controls over financial reporting for PSNH. Management s report on behalf of PSNH was not subject to attestation pursuant to temporary rules of the Securities and Exchange Commission that permit this company to provide only management s report in this combined 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 the 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 internal controls over financial reporting were effective as of December 31, 2008.

February 27, 2009

Report of Independent Registered Public Accounting Firm

To the Board of 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, 2008 and 2007, 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, 2008. Our audits also included the consolidated financial statement schedules listed in the Index at Item 15. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules 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, 2008 and 2007, 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. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements 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 27, 2009

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	At December 31,	
(Thousands of Dollars)	2008	2007
ASSETS		
Current Assets:		
Cash	$ 195	$ 450
Receivables, less provision for uncollectible accounts of $4,165 in 2008 and $2,675 in 2007	108,857	97,749
Notes receivable from affiliated companies	53,800	-
Accounts receivable from affiliated companies	264	817
Unbilled revenues	41,449	45,607
Taxes receivable	8,809	255
Fuel, materials and supplies	113,121	72,215
Derivative assets - current	843	6,146
Accumulated deferred income taxes - current	27,345	-
Prepayments and other	15,380	14,327
	370,063	237,566
Property, Plant and Equipment:		
Electric utility	2,238,515	2,010,220
Less: Accumulated depreciation	771,282	737,917
	1,467,233	1,272,303
Construction work in progress	113,752	116,102
	1,580,985	1,388,405
Deferred Debits and Other Assets:		
Regulatory assets	549,934	401,374
Derivative assets - long-term	3,826	12,075

Other		124,025		67,549
		677,785		480,998
Total Assets	$	2,628,833	$	2,106,969

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,	
(Thousands of Dollars)	2008	2007
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 45,227	$ 10,000
Notes payable to affiliated companies	-	11,300
Accounts payable	160,692	91,356
Accounts payable to affiliated companies	31,140	15,717
Accrued interest	11,778	9,175
Derivative liabilities - current	77,369	2,453
Other	23,422	22,664
	349,628	162,665
Rate Reduction Bonds	235,139	282,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes - long-term	253,670	192,094
Accumulated deferred investment tax credits	355	582
Deferred contractual obligations	23,820	28,215
Regulatory liabilities	111,403	127,569
Derivative liabilities - long-term	14,846	-
Accrued pension	236,332	138,346
Accrued postretirement benefits	41,849	29,057
Other	41,297	31,559
	723,572	547,422
Capitalization:		
Long-Term Debt	686,779	576,997
Common Stockholder's Equity:		

Common stock, $1 par value - authorized 100,000,000 shares; 301 shares outstanding in 2008 and 2007	-	-
Capital surplus, paid in	351,245	275,569
Retained earnings	283,219	261,528
Accumulated other comprehensive (loss)/income	(749)	770
Common Stockholder's Equity	633,715	537,867
Total Capitalization	1,320,494	1,114,864
Commitments and Contingencies (Note 7)		
Total Liabilities and Capitalization	$ 2,628,833	$ 2,106,969

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2008	2007	2006
Operating Revenues	$ 1,141,202	$ 1,083,072	$ 1,140,900
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	558,313	530,680	588,132
Other	215,497	208,691	178,577
Maintenance	90,933	74,070	71,400
Depreciation	56,321	53,315	49,740
Amortization of regulatory assets, net	9,254	7,470	53,156
Amortization of rate reduction bonds	45,644	52,344	49,370
Taxes other than income taxes	42,291	39,671	37,640
Total operating expenses	1,018,253	966,241	1,028,015
Operating Income	122,949	116,831	112,885
Interest Expense:			
Interest on long-term debt	32,655	26,029	24,100
Interest on rate reduction bonds	15,969	18,013	20,828
Other interest	1,539	2,243	829
Interest expense, net	50,163	46,285	45,757
Other Income, Net	7,277	6,682	7,378
Income Before Income Tax Expense	80,063	77,228	74,506
Income Tax Expense	21,996	22,794	39,183
Net Income	$ 58,067	$ 54,434	$ 35,323

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 58,067	$ 54,434	$ 35,323
Other comprehensive (loss)/income, net of tax:			
Qualified cash flow hedging instruments	(1,418)	605	-
Changes in unrealized gains on securities	(101)	(11)	32
Minimum SERP liability	-	-	61
Other comprehensive (loss)/income, net of tax	(1,519)	594	93
Comprehensive Income	$ 56,548	$ 55,028	$ 35,416

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

(Thousands of Dollars, except share information)	Common Stock Shares	Common Stock Amounts	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total
Balance at January 1, 2006	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 contributions 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 FIN48 - 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 contributions 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
Net income for 2008				58,067		58,067
Dividends on common stock				(36,376)		(36,376)
Allocation of benefits - ESOP			93			93
Capital contributions from NU parent			75,583			75,583
Other comprehensive loss					(1,519)	(1,519)
Balance at December 31, 2008	301	$ -	$ 351,245	$ 283,219	$ (749)	$ 633,715

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,		
(Thousands of Dollars)	2008	2007	2006
Operating activities:			
Net income	$ 58,067	$ 54,434	$ 35,323
Adjustments to reconcile to net cash flows provided by operating activities:			
Depreciation	56,321	53,315	49,740
Deferred income taxes	25,001	(4,726)	(21,929)
Amortization of investment tax credits	(227)	(295)	(353)
Bad debt expense	5,661	3,433	4,208
Pension and PBOP expense and contributions, net of capitalized portion	12,350	7,258	17,310
Allowance for equity funds used during construction	(4,374)	(1,958)	(4,367)
Amortization of rate reduction bonds	45,644	52,344	49,370
Amortization of regulatory assets, net	9,254	7,470	53,156
Regulatory refunds and underrecoveries	(23,848)	(6,167)	(6,850)
Net settlement of cash flow hedge instruments	(1,730)	-	-
Deferred contractual obligations	(4,978)	(6,365)	(12,589)
Increase in other deferred debits	(19,716)	(7,787)	(9,128)
(Decrease)/increase in other deferred credits	(64)	125	(4,101)
Other adjustments	(2,808)	(1,939)	(659)
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(12,058)	(15,799)	27,637
Taxes receivable/accrued	(2,117)	4,144	(11,857)
Fuel, materials and supplies	(26,209)	15,882	(12,036)
Other current assets	(1,516)	(1,949)	5,106

Accounts payable	41,959	(8,178)	14,073
Other current liabilities	8,664	4,051	1,764
Net cash flows provided by operating activities	163,276	147,293	173,818
Investing Activities:			
Investments in property and plant	(238,912)	(167,712)	(126,657)
Increase in NU Money Pool lending	(53,800)	-	-
Proceeds from sales of marketable securities	5,380	3,454	3,788
Purchases of marketable securities	(5,508)	(3,692)	(4,059)
Other investing activities	4,735	5,921	2,564
Net cash flows used in investing activities	(288,105)	(162,029)	(124,364)
Financing Activities:			
Cash dividends on common stock	(36,376)	(30,720)	(41,741)
Increase in short-term debt	35,227	10,000	-
(Decrease)/increase in NU Money Pool borrowings	(11,300)	(25,200)	20,600
Capital contributions from NU parent	75,583	44,194	21,693
Issuance of long-term debt	110,000	70,000	-
Retirements of rate reduction bonds	(46,879)	(51,813)	(48,861)
Other financing activities	(1,681)	(1,306)	(1,141)
Net cash flows provided by/(used in) financing activities	124,574	15,155	(49,450)
Net (decrease)/increase in cash	(255)	419	4
Cash - beginning of year	450	31	27
Cash - end of year	$ 195	$ 450	$ 31
Supplemental Cash Flow Information:			
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 49,990	$ 50,237	$ 49,305
Income taxes	$ 1,023	$ 26,167	$ 75,198
Non-cash investing activities:			
Capital expenditures incurred but not paid	$ 31,391	$ 37,811	$ 15,036

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

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. This combined annual report does not include an attestation report from Deloitte & Touche LLP regarding the internal controls over financial reporting for WMECO. Management s report on behalf of WMECO was not subject to attestation pursuant to temporary rules of the Securities and Exchange Commission that permit this company to provide only management s report in this combined 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 the 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 internal controls over financial reporting were effective as of December 31, 2008.

February 27, 2009

Report of Independent Registered Public Accounting Firm

To the Board of 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, 2008 and 2007, 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, 2008. Our audits also included the consolidated financial statement schedules listed in the Index at Item 15. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules 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, 2008 and 2007, 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. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements 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 27, 2009

WESTERN MASSACHUSETTS ELECTRIC
COMPANY AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

	At December 31,	
(Thousands of Dollars)	2008	2007
ASSETS		
Current Assets:		
Cash	$ -	$ 1,110
Receivables, less provision for uncollectible accounts of $6,571 in 2008 and $5,699 in 2007	56,802	49,578
Accounts receivable from affiliated companies	575	258
Unbilled revenues	16,694	17,990
Taxes receivable	5,499	3,382
Materials and supplies	3,825	2,353
Marketable securities - current	46,428	31,286
Prepayments and other	2,380	2,661
	132,203	108,618
Property, Plant and Equipment:		
Electric utility	781,486	728,712
Less: Accumulated depreciation	214,694	205,743
	566,792	522,969
Construction work in progress	57,413	36,388
	624,205	559,357
Deferred Debits and Other Assets:		
Regulatory assets	268,417	193,921
Prepaid pension	-	90,015
Marketable securities - long-term	9,322	25,078
Other	14,342	14,099

		292,081		323,113
Total Assets	$	1,048,489	$	991,088

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

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WESTERN MASSACHUSETTS ELECTRIC
COMPANY AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

	At December 31,	
(Thousands of Dollars)	2008	2007
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 29,850	$ -
Notes payable to affiliated companies	31,600	14,900
Accounts payable	50,161	30,636
Accounts payable to affiliated companies	15,047	7,480
Accrued interest	5,824	5,498
Other	10,715	10,489
	143,197	69,003
Rate Reduction Bonds	73,176	86,731
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes - long-term	187,283	187,139
Accumulated deferred investment tax credits	1,753	2,015
Deferred contractual obligations	36,509	41,958
Regulatory liabilities	29,826	39,437
Accrued pension	3,577	-
Accrued postretirement benefits	18,078	12,668
Other	13,072	5,015
	290,098	288,232
Capitalization:		
Long-Term Debt	303,868	303,872
Common Stockholder's Equity:		
Common stock, $25 par value - authorized		

1,072,471 shares; 434,653 shares outstanding				
in 2008 and 2007		10,866		10,866
Capital surplus, paid in		144,545		128,228
Retained earnings		82,549		103,925
Accumulated other comprehensive income		190		231
Common Stockholder's Equity		238,150		243,250
Total Capitalization		542,018		547,122
Commitments and Contingencies (Note 7)				
Total Liabilities and Capitalization	$	1,048,489	$	991,088

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,		
(Thousands of Dollars)	2008	2007	2006
Operating Revenues	$ 441,527	$ 464,745	$ 431,509
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	237,369	236,582	280,158
Other	76,929	98,837	81,969
Maintenance	20,720	18,618	15,821
Depreciation	21,025	20,868	17,204
Amortization of regulatory assets/(liabilities), net	12,445	10,601	(27,516)
Amortization of rate reduction bonds	13,625	12,766	11,968
Taxes other than income taxes	12,867	12,322	11,932
Total operating expenses	394,980	410,594	391,536
Operating Income	46,547	54,151	39,973
Interest Expense:			
Interest on long-term debt	13,244	11,577	10,671
Interest on rate reduction bonds	5,133	5,839	6,723
Other interest	1,256	2,430	1,507
Interest expense, net	19,633	19,846	18,901
Other Income, Net	1,961	3,885	2,338
Income Before Income Tax Expense	28,875	38,190	23,410
Income Tax Expense	10,545	14,586	7,766
Net Income	$ 18,330	$ 23,604	$ 15,644

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME						
Net Income	$	18,330	$	23,604	$	15,644
Other comprehensive (loss)/income, net of tax:						
Qualified cash flow hedging instruments		(79)		(704)		(99)
Changes in unrealized gains on securities		38		42		226
Minimum SERP liability		-		-		72
Other comprehensive (loss)/income, net of tax		(41)		(662)		199
Comprehensive Income	$	18,289	$	22,942	$	15,843

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

(Thousands of Dollars, except share information)	Common Stock Shares	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance at January 1, 2006	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 contributions 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 contributions 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
Net income for 2008				18,330		18,330
Dividends on common stock				(39,706)		(39,706)
Allocation of benefits - ESOP			36			36
Capital contributions from NU parent			16,281			16,281
Other comprehensive loss					(41)	(41)
Balance at December 31, 2008	434,653	$ 10,866	$ 144,545	$ 82,549	$ 190	$ 238,150

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,		
(Thousands of Dollars)	2008	2007	2006
Operating Activities:			
Net income	$ 18,330	$ 23,604	$ 15,644
Adjustments to reconcile to net cash flows provided by operating activities:			
Depreciation	21,025	20,868	17,204
Deferred income taxes	12,222	(15,332)	(17,192)
Amortization of investment tax credits	(263)	(304)	(336)
Bad debt expense	8,185	6,922	5,503
Pension and PBOP income and contributions, net of capitalized portion	(4,844)	(3,050)	(1,044)
Allowance for equity funds used during construction	(1,183)	(156)	(184)
Impairment of marketable securities	2,248	636	-
Amortization of rate reduction bonds	13,625	12,766	11,968
Amortization of regulatory assets/(liabilities), net	12,445	10,601	(27,516)
Regulatory (underrecoveries)/overrecoveries	(17,093)	32,129	10,327
Deferred contractual obligations	(5,822)	(7,568)	(16,807)
(Increase)/decrease in other deferred debits	(1,270)	836	3,364
Increase/(decrease) in other deferred credits	922	652	119
Other adjustments	(4,329)	(1,469)	1,904
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(14,210)	(9,749)	(4,600)
Materials and supplies	(1,490)	(478)	(461)
Other current assets	703	(1,300)	(183)
Accounts payable	22,186	1,417	(7,544)

Taxes receivable/accrued	4,081	(35,014)	25,995
Other current liabilities	2,015	1,537	176
Net cash flows provided by operating activities	67,483	37,548	16,337
Investing Activities:			
Investments in property and plant	(78,253)	(47,315)	(42,818)
Proceeds from sales of marketable securities	169,056	196,865	123,148
Purchases of marketable securities	(169,902)	(199,803)	(125,782)
Other investing activities	939	929	2,637
Net cash flows used in investing activities	(78,160)	(49,324)	(42,815)
Financing Activities:			
Cash dividends on common stock	(39,706)	(12,779)	(7,946)
Increase in short-term debt	29,850	-	-
Issuance of long-term debt	-	40,000	-
Retirements of rate reduction bonds	(13,555)	(12,697)	(11,903)
Increase/(decrease) in NU Money Pool borrowings	16,700	(15,900)	15,900
Capital contributions from NU parent	16,281	13,607	31,945
Other financing activities	(3)	(681)	(183)
Net cash flows provided by financing activities	9,567	11,550	27,813
Net (decrease)/increase in cash	(1,110)	(226)	1,335
Cash - beginning of year	1,110	1,336	1
Cash - end of year	$ -	$ 1,110	$ 1,336
Supplemental Cash Flow Information:			
Cash paid/(received) during the year for:			
Interest, net of amounts capitalized	$ 19,979	$ 20,259	$ 20,140
Income taxes	$ (5,872)	$ 65,595	$ (677)
Non-cash investing activities:			
Capital expenditures incurred but not paid	$ 11,465	$ 6,593	$ 2,019

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1.

Summary of Significant Accounting Policies (All Companies)

A.

About Northeast Utilities, The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company

Consolidated: Northeast Utilities (NU or the company) is the parent company of the regulated companies and NU Enterprises, Inc. (NU Enterprises), as described below. NU was formed on July 1, 1966 when The Connecticut Light and Power Company (CL&P), Western Massachusetts Electric Company (WMECO) and The Hartford Electric Light Company affiliated under the common ownership of the NU system. In 1967, Holyoke Water Power Company (HWP) joined the affiliation. In 1992, Public Service Company of New Hampshire (PSNH) became a subsidiary of NU parent. On March 1, 2000, gas became an integral part of NU's Connecticut operations when NU's merger with Yankee Energy System, Inc. (Yankee) and its principal subsidiary, Yankee Gas Services Company (Yankee Gas), was completed. CL&P, PSNH and WMECO are reporting companies 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 the regulated electric companies, NU Enterprises and other NU companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. The regulated companies are subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the Connecticut Department of Public Utility Control (DPUC) for CL&P and Yankee Gas, the New Hampshire Public Utilities Commission (NHPUC), as well as certain regulatory oversight by the Vermont Department of Public Service and the Maine Public Utilities Commission for PSNH and the Massachusetts Department of Public Utilities (DPU) for WMECO).

Regulated Companies: CL&P, PSNH and WMECO furnish franchised retail electric service in Connecticut, New Hampshire and Massachusetts, respectively. Yankee Gas owns and operates Connecticut s largest natural gas distribution system. CL&P, PSNH and WMECO's results include the operations of its distribution and transmission segments. PSNH's distribution results include the operations of its generation business. Yankee Gas results include the operations of its gas distribution segment.

NU Enterprises: NU Enterprises is the parent company of Select Energy, Inc. (Select Energy), E. S. Boulos Company (Boulos), Northeast Generation Services Company (NGS), NGS Mechanical, Inc. and Select Energy Contracting, Inc.

(SECI), which are collectively referred to as NU Enterprises. For information regarding NU's exit from certain of these businesses, see Note 15, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements.

B.

Presentation

The consolidated financial statements of NU, CL&P, PSNH and WMECO include the accounts of all their respective subsidiaries. CL&P's subsidiaries are CL&P Receivables Corporation (CRC) and CL&P Funding LLC. PSNH's subsidiaries are PSNH Funding LLC, PSNH Funding LLC2 and Properties, Inc. WMECO's subsidiary is 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.

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

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

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Northeast Generation Company (NGC), including certain components of NGS,

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The Mt. Tom generating plant (Mt. Tom) previously owned by HWP,

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Select Energy Services, Inc. (SESI) and its wholly-owned subsidiaries HEC/Tobyhanna Energy Project, Inc. and HEC/CJTS Energy Center LLC,

.

A portion of the former Woods Electrical Co., Inc. (Woods Electrical), and

.

SECI (including Reeds Ferry Supply Co., Inc.).

For further information regarding discontinued operations, see Note 15, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements.

C.

Accounting Standards Issued But Not Yet Adopted

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

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

SFAS No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value, was issued in 2006 and applied in 2008 to the fair value measurements of financial assets and liabilities of NU and its subsidiaries. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 is required to be applied to nonrecurring fair value measurements of non-financial assets and liabilities beginning in 2009, including asset retirement obligations (ARO) and goodwill and other impairment analyses. Implementation of SFAS No. 157 to non-financial assets and liabilities is not expected to have a material impact on the company s consolidated financial statements or the consolidated financial statements of CL&P, PSNH or WMECO.

D.

Revenues

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

The regulated companies record monthly, day ahead and real time energy purchases and sales, net in accordance with The Emerging Issues Task Force (EITF) Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as defined in EITF Issue No. 02-3." Revenues associated with derivative instruments to purchase and sell in the day ahead and real time markets are recorded net in revenues and fuel, purchased and net interchange power.

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

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

Regulated Companies' Transmission Revenues - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of NU s wholesale transmission revenues, including CL&P, PSNH, and WMECO, are collected under the New England Independent System Operator (ISO-NE) FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Schedule 21 - NU rate schedules to recover fees for transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, including CL&P, PSNH, and WMECO's transmission businesses, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The Schedule 21 - NU rate, administered by NU, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 100 percent of the construction work in progress (CWIP) that is included in rate base on the New England East-West Solutions (NEEWS) projects. The Schedule 21 - NU rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and Schedule 21 - NU rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to customers. At December 31, 2008, the Schedule 21 - NU rates were in a total underrecovery position of $4.6 million ($3.8 million for CL&P, $0.6 million for PSNH and $0.2 million for WMECO) that will be collected from customers in mid-2009.

Regulated Companies' Transmission Revenues - Retail Rates: A significant portion of the NU consolidated transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. CL&P, PSNH and WMECO each have a retail transmission cost tracking mechanism as part of their rates, which allows the companies to charge their retail customers for transmission costs on a timely basis.

NU Enterprises: NU Enterprises' revenues are recognized at different times for its different business lines. Service revenues are recognized as services are provided, often on a percentage of completion basis. Wholesale marketing revenues are recognized through mark-to-market accounting on underlying derivative contracts and recorded in fuel, purchased and net interchange power. This net presentation of the mark-to-market and settlement amounts is required because NU Enterprises cannot assert that physical delivery of contract quantities is deemed probable.

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

E.

Derivative Accounting

CL&P and PSNH's contracts for the purchase and sale of energy or energy related products are derivatives, along with all but one of Select Energy's remaining wholesale marketing contracts. The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative. Non-derivative contracts are recorded at the time of delivery or settlement.

The application of derivative accounting under SFAS No. 133 is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of the normal purchases and sales exception, identifying, electing and designating hedge relationships, assessing and measuring hedge ineffectiveness, and determining the fair value of derivatives. All of these judgments, depending upon their timing and effect, can have a significant impact on the consolidated financial statements.

The fair value of derivatives is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the company determines whether it is a derivative by using amounts referenced in default provisions and other relevant sections of the contract. The estimated quantities to be served are updated during the term of the contract, and such updates can have a material impact on mark-to-market amounts. The fair value of derivative assets and liabilities with the same counterparty are offset as permitted under FASB Interpretation No. (FIN) 39, "Offsetting of Amounts Related to Certain Contracts - an Interpretation of APB Opinion No. 10 and FASB Statement No. 105."

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

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

Most of the contracts that comprise Select Energy s wholesale marketing activities are derivatives, and many of NU s regulated company contracts for the purchase or sale of energy or energy-related products are derivatives.

EITF 03-11 addresses income statement classification of derivatives that are not related to energy trading activities. In accordance with EITF 03-11, the remaining wholesale marketing contracts, which are marked-to-market derivative contracts, are not considered to be held for trading purposes, and sales and purchase activity is reported on a net basis in fuel, purchased and net interchange power.

EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," prohibited recording the initial gains and losses on derivative contracts if their estimated fair values are based on significant non-observable inputs. Based upon the significance of non-observable capacity prices to their valuation, the estimated initial fair values of CL&P s contracts for differences (CfDs) were not recorded on the balance sheet as of December 31, 2007. These initial losses were recorded upon adoption of SFAS No. 157 on January 1, 2008. For further information, see Note 1F, "Fair Value Measurements," to the consolidated financial statements.

For further information regarding derivative contracts of NU, CL&P, PSNH and WMECO, and their accounting, see Note 3, "Derivative Instruments," to the consolidated financial statements.

F.

Fair Value Measurements

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

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Defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price).

.

Establishes a three-level fair value hierarchy based upon the observability of inputs to the valuations of assets and liabilities.

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Requires consideration of the company's own creditworthiness and risk of nonperformance when valuing its liabilities.

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Required prospective implementation with adjustments to fair value reflected in earnings, similar to a change in estimate, with exceptions including recognition of previously deferred initial gains or losses described below.

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Required recognition in retained earnings of previously deferred initial gains or losses on derivative contracts whose estimated fair values are based on significant unobservable inputs. Recognition of the initial gains or losses was previously prohibited under EITF 02-3. CL&P s initial gains and losses on its CfDs that would have been recorded in retained earnings upon adoption were recorded as regulatory assets and liabilities because their costs or benefits are expected to be fully recovered from or refunded to customers.

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

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

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

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

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

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

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

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

Determination of Fair Value: The following is a description of the valuation techniques utilized in NU, CL&P, PSNH, and WMECO's fair value measurements:

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

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

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

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

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

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

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

G.

Regulatory Accounting

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

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

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

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

	At December 31,					
	2008			**2007**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Securitized assets	$ 377.8	$ 227.6	$ 72.0	$ 548.2	$ 273.2	$ 85.6
Income taxes, net	306.8	16.1	20.7	279.4	10.3	38.2
Deferred benefit costs	537.7	142.9	113.5	72.2	50.4	8.2
Unrecovered contractual obligations	132.6	-	36.5	148.0	-	42.0
Regulatory assets offsetting regulated company derivative liabilities	751.9	92.1	-	119.8	2.5	-
CL&P undercollections	75.2	-	-	90.6	-	-
WMECO recoverable nuclear costs	-	-	5.0	-	-	9.3
Other regulatory assets	92.1	71.2	20.7	71.8	65.0	10.6
Totals	$ 2,274.1	$ 549.9	$ 268.4	$ 1,330.0	$ 401.4	$ 193.9

Additionally, the regulated companies had $68.3 million ($62.7 million for PSNH and $5.6 million for CL&P) and $11.9 million (CL&P) of regulatory costs at December 31, 2008 and 2007, respectively, which were included in deferred debits and other assets - other on the accompanying consolidated balance sheets. These amounts represent incurred costs that have not yet been approved for recovery by the applicable regulatory agency. The $62.7 million for PSNH relates to costs incurred relating to December 2008 storm restorations that met NHPUC specified criteria for deferral to a major storm cost reserve. Management believes these costs are recoverable in future cost-of-service regulated rates.

Securitized Assets: In March 2001, CL&P issued $1.4 billion in rate reduction bonds (RRBs). CL&P used $1.1 billion of the proceeds from that issuance to buyout or buydown certain contracts with IPPs. The unamortized CL&P securitized asset balance was $322.9 million and $468.6 million at December 31, 2008 and 2007, respectively, which includes $44.9 million and $65.1 million, respectively, related to unrecovered contractual obligations. CL&P also used the proceeds from the issuance of the RRBs to securitize a portion of its SFAS No. 109, "Accounting for Income Taxes," regulatory asset. The securitized SFAS No. 109 regulatory asset had an unamortized balance of $54.9 million and $79.6 million at December 31, 2008 and 2007, respectively.

In April 2001, PSNH issued RRBs in the amount of $525 million. PSNH used the majority of the proceeds from that issuance to buydown its affiliated power contracts with North Atlantic Energy Corporation. The unamortized PSNH securitized asset balance was $227.6 million and $272.4 million at December 31, 2008 and 2007, respectively. In January 2002, PSNH issued an additional $50 million in RRBs and used the proceeds from that issuance to repay short-term debt that was incurred to buyout a purchased-power contract in December 2001. The unamortized PSNH securitized asset balance for the January 2002 issuance was $0.8 million at December 31, 2007. The January 2002 RRBs were paid in full in the first quarter of 2008.

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

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

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

Deferred Benefit Costs: On December 31, 2006, the company implemented SFAS No. 158, "Employers Accounting for Defined Benefit Pension and Other Postretirement Plans." SFAS No. 158 applies to NU s Pension Plan, SERP, and postretirement benefits other than pension (PBOP) Plan and requires an additional benefit liability to be recorded with an offset to accumulated other comprehensive income in shareholders equity, which is remeasured annually. However, because the regulated companies are cost-of-service rate regulated entities under SFAS No. 71, offsets were recorded as a regulatory asset at December 31, 2008 and 2007 as these amounts have been and continue to be recoverable in cost-of-service regulated rates. Regulatory accounting was also applied to the portions of the Northeast Utilities Service Company (NUSCO) costs that support the regulated companies, as these amounts are also recoverable. The deferred benefit costs of CL&P and PSNH are not in rate base and are being recovered over a period of up to 12 years. WMECO s deferred benefit costs are in rate base.

Unrecovered Contractual Obligations: Under the terms of contracts with the Connecticut Yankee Atomic Power Company (CYAPC), Yankee Atomic Electric Company (YAEC), and Maine Yankee Atomic Power Company (MYAPC) (Yankee Companies), CL&P, PSNH, and WMECO are responsible for their proportionate share of the remaining costs of the units, including decommissioning. A portion of these amounts was recorded as unrecovered contractual obligations regulatory assets at December 31, 2008 and 2007. A portion of these obligations for CL&P was securitized in 2001 and was included in securitized regulatory assets. Amounts for CL&P are being recovered through the Competitive Transition Assessment (CTA). Amounts for WMECO are being recovered along with other stranded costs. Amounts for PSNH were fully recovered by December 31, 2006.

Regulatory Assets Offsetting Regulated Company Derivative Liabilities: The regulatory assets offsetting derivative liabilities relate to the fair value of contracts used to purchase power and other related contracts that will be collected from customers in the future. Included in these amounts are $677.8 million and $86.7 million at December 31, 2008 and 2007, respectively, of derivative liabilities relating to CL&P s capacity contracts, referred to as CfDs. See Note 3, "Derivative Instruments," to the consolidated financial statements for further information. This asset is excluded from rate base.

CL&P Undercollections: The System Benefits Charge (SBC) allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes and displaced workers protection costs. At December 31, 2008 and 2007, SBC undercollections totaled $43.3 million and $36.6 million, respectively.

The Generation Service Charge (GSC) allows CL&P to recover the costs of the procurement of energy for standard service, which includes forward capacity market charges. The Federally Mandated Congestion Charges (FMCC) mechanism allows CL&P to recover the costs of power market rules by the FERC, including Reliability Must Run (RMR) costs. At December 31, 2008, CL&P s GSC and FMCC was recorded as a $31.9 million regulatory asset as GSC and FMCC unrecovered costs were in excess of GSC and FMCC collections. At December 31, 2007, GSC and FMCC collections were in excess of GSC and FMCC costs, and a $119.2 million regulatory liability was recorded.

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

WMECO Recoverable Nuclear Costs: Included in recoverable nuclear costs at December 31, 2008 and 2007 are costs primarily related to Millstone 1 recoverable nuclear costs for the undepreciated plant and related assets at the time Millstone 1 was shutdown.

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

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

	At December 31,					
		2008			**2007**	
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Asset retirement obligations	$ 23.1	$ 13.9	$ 2.8	$ 22.2	$ 13.3	$ 2.7
Losses on reacquired debt	14.0	10.1	0.5	15.4	10.9	0.5
Environmental costs	-	2.0	-	-	2.3	-
Storm reserves	-	8.2	11.1	-	6.8	-
Buyout/buydown of other IPP contracts	0.8	13.4	-	1.1	15.0	-
	-	-	-	10.4	-	-

Write-off of uncollectible hardship receivables						
Conservation & load management deferral	17.6	-	0.2	9.9	-	2.6
Recoverable energy costs	-	-	0.7	-	-	1.3
Other	36.6	23.6	5.4	12.8	16.7	3.5
Total other regulatory assets	$ 92.1	$ 71.2	$ 20.7	$ 71.8	$ 65.0	$ 10.6

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

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

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

	At December 31,					
	2008			2007		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Cost of removal	$ 91.2	$ 64.7	$ 19.2	$ 116.6	$ 72.8	$ 21.5
Regulatory liabilities offsetting regulated company derivative assets	131.3	4.6	-	313.0	17.2	-
CL&P overcollections	69.5	-	-	119.2	-	-
CL&P AFUDC transmission incentive (Note 1K)	47.6	-	-	21.4	-	-
PSNH deferred ES revenue, net	-	33.0	-	-	17.6	-
PSNH deferred environmental credit revenue	-	-	-	-	10.1	-
WMECO transition charge overcollections	-	-	5.7	-	-	2.4
WMECO transmission refunds	-	-	0.2	-	-	5.8
WMECO pension/PBOP tracker	-	-	2.0	-	-	4.6
WMECO default service overcollections	-	-	1.3	-	-	3.9
Other regulatory liabilities	23.9	9.1	1.4	31.3	9.9	1.2
Totals	$ 363.5	$ 111.4	$ 29.8	$ 601.5	$ 127.6	$ 39.4

Cost of Removal: NU s regulated companies currently recover amounts in rates for future costs of removal of plant assets. These amounts are classified as regulatory liabilities on the accompanying consolidated balance sheets. This liability is included in rate base.

Regulatory Liabilities Offsetting Regulated Company Derivative Assets: The regulatory liabilities offsetting derivative assets relate to the fair value of contracts used to purchase power and other related contracts that will benefit ratepayers in the future. See Note 3, "Derivative Instruments," to the consolidated financial statements for further information. This liability is excluded from rate base.

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

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

PSNH 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 was refunded to customers in 2008.

WMECO Transition Charge Overcollections: WMECO recovers it stranded costs through a transition charge. This amount represents the cumulative excess of transition cost revenues over transition cost expenses.

WMECO 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.

WMECO 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.

*WMECO Default Service Overcollection*s: The default service rate allows WMECO to recover the costs of the procurement of energy for basic service, which includes forward capacity market charges.

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

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

H.

Income Taxes

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

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

	At December 31,								
	2008			**2007**			**2006**		
	CL&P	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
(Millions of Dollars)									
Current income taxes:									
Federal	$ 13.9	$ 0.8	$ (1.4)	$ 36.3	$ 21.9	$ 26.4	$ 104.9	$ 50.5	$ 25.5
State	19.0	(3.6)	-	(10.0)	5.9	3.8	3.8	11.0	(0.2)
Total current	32.9	(2.8)	(1.4)	26.3	27.8	30.2	108.7	61.5	25.3
Deferred income taxes, net:									

Federal	68.0	17.4	10.4	23.5	(1.7)	(12.9)	(69.2)	(17.1)	(21.2)
State	(20.4)	7.6	1.8	5.2	(3.0)	(2.4)	(21.5)	(4.8)	4.0
Total deferred	47.6	25.0	12.2	28.7	(4.7)	(15.3)	(90.7)	(21.9)	(17.2)
Investment tax credits, net	(2.6)	(0.2)	(0.2)	(2.6)	(0.3)	(0.3)	(62.0)	(0.4)	(0.3)
Income tax expense/(benefit)	$ 77.9	$ 22.0	$ 10.6	$ 52.4	$ 22.8	$ 14.6	$ (44.0)	$ 39.2	$ 7.8

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

*Not meaningful.

	For the Years Ended December 31,							
	2008			2007			200	
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO	CL&P	PSN
	(Millions of Dollars, except percentages)							
Income from continuing operations before income tax expense/(benefit)	$ 269.0	$ 80.1	$ 28.9	$ 185.9	$ 77.2	$ 38.2	$ 156.0	$ 74.
Expected federal income tax expense/(benefit)	94.2	28.0	10.1	65.1	27.0	13.4	54.6	26.
Tax effect of differences:								
Depreciation	(11.1)	(1.8)	0.1	(6.6)	-	0.5	(1.8)	
Amortization of regulatory assets	0.1	-	0.1	-	-	-	-	13.
Investment tax credit amortization (Including $59.3 million in 2006 related to the CL&P PLR)	(2.6)	(0.2)	(0.2)	(2.6)	(0.3)	(0.3)	(62.0)	
Other federal tax credits	(1.2)	(3.4)	-	(1.1)	(3.1)	-	-	(0.
State income taxes, net of federal impact	(18.5)	2.6	1.2	(11.9)	1.9	0.9	(7.4)	4.
Excess deferred income taxes - CL&P PLR	-	-	-	-	-	-	(14.7)	
Deferred tax adjustment - sale to affiliate	-	-	-	-	-	-	(4.4)	
Medicare subsidy	(1.5)	(0.8)	(0.4)	(1.8)	(0.9)	(0.4)	(2.2)	(1.
Tax asset valuation allowance/reserve adjustments	19.8	-	-	10.9	-	-	(3.8)	
Other, net	(1.3)	(2.4)	(0.3)	0.4	(1.8)	0.5	(2.3)	(2.

Income tax expense/(benefit)	$ 77.9	$ 22.0	$ 10.6	$ 52.4	$ 22.8	$ 14.6	$ (44.0)	$ 39.
Effective tax rate	28.9 %	27.5 %	36.7 %	28.2 %	29.5 %	38.2 %	* %	52.

*Not meaningful.

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

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

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

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

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

Net deferred tax liabilities	$	1,205.8	$	1,107.9

	At December 31,					
	2008			2007		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Deferred tax liabilities - current:						
Derivative asset and change in fair value of energy contracts	$ 12.2	$ 0.3	$ -	$ 21.8	$ -	$ -
Property tax accruals and other	32.3	4.4	2.5	35.3	6.2	2.3
Total deferred tax liabilities - current	44.5	4.7	2.5	57.1	6.2	2.3
Deferred tax assets - current:						
Derivative liability and change in fair value of energy contracts	3.5	30.6	-	-	1.0	-
Allowance for uncollectible accounts and other	24.3	1.4	2.6	16.3	0.9	2.2
Total deferred tax assets - current	27.8	32.0	2.6	16.3	1.9	2.2
Net deferred tax liabilities/(assets) - current	16.7	(27.3)	(0.1)	40.8	4.3	0.1
Deferred tax liabilities - long-term:						
Accelerated depreciation and other plant-related differences	638.0	216.3	135.2	546.8	162.6	113.4
Employee benefits	-	-	-	133.2	-	33.5
Regulatory amounts:						
Securitized contract termination costs	19.3	88.4	27.6	28.2	106.0	32.7
Other regulatory deferrals	548.2	134.2	53.4	70.8	14.0	-
Income tax gross-up	158.5	9.1	15.7	161.3	-	17.8
Derivative assets	85.8	1.5	-	111.1	-	-
Other	9.0	6.7	1.8	16.0	23.2	19.8

Total deferred tax liabilities - long-term	1,458.8	456.2	233.7	1,067.4	305.8	217.2
Deferred tax assets - long-term:						
Regulatory deferrals	82.3	51.1	12.1	168.5	27.5	16.9
Employee benefits	101.9	121.5	13.1	63.6	77.2	7.1
Income tax gross-up	14.3	2.8	7.3	18.2	-	2.8
Derivative liability	338.2	5.9	-	54.2	-	-
Other	110.7	21.2	13.9	64.1	9.0	3.3
Net deferred tax assets - long-term	647.4	202.5	46.4	368.6	113.7	30.1
Net deferred tax liabilities - long-term	811.4	253.7	187.3	698.8	192.1	187.1
Net deferred tax liabilities	$ 828.1	$ 226.4	$ 187.2	$ 739.6	$ 196.4	$ 187.2

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

At December 31, 2008, NU had state net operating loss (NOL) carryforwards of $269.1 million that expire between December 31, 2010 and December 31, 2028 and state credit carryforwards of $90.8 million that expire by December 31, 2013. At December 31, 2007, NU had state NOL carryforwards of $434.1 million that expire between December 31, 2009 and December 31, 2027 and state credit carryforwards of $61.3 million that expire by December 31, 2012. The NOL carryforward deferred tax asset has been fully reserved by a valuation allowance. At December 31, 2008, CL&P had state tax credit carryforwards of $64.4 million that expire by 2013. At December 31, 2007, CL&P had state tax credit carry forwards of $38 million that expire by 2012.

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

Effective on January 1, 2007, NU and its subsidiaries, including CL&P, PSNH and 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, NU consolidated, CL&P, PSNH and WMECO recorded estimates for uncertain tax positions in accordance with SFAS No. 5, "Accounting for Contingencies."

As a result of implementing FIN 48, NU consolidated 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, including CL&P, PSNH and WMECO reductions/(increases) of $24 million, $(1.6) million and $(0.4) million, respectively.

Interest and Penalties: Effective on January 1, 2007, the accounting policy of NU consolidated, CL&P, PSNH and WMECO for the classification of interest and penalties related to FIN 48 is as follows:

Interest on uncertain tax positions is recorded and generally classified as a component of other interest expense. However, when resolution of uncertainties results in the company receiving interest income, any related interest benefit is recorded in other income, net on the accompanying consolidated statements of income. No penalties have been recorded under FIN 48. If penalties are recorded in the future, then the estimated penalties would be classified as a component of other income, net on the accompanying consolidated statements of income. The components of interest on uncertain tax positions by company in 2008 and 2007 are as follows:

Other Interest	**For the Years Ended December 31,**				**Accrued Interest**	**At December 31,**			
Expense/(Income)	**2008**		**2007**		**Expense/(Income)**	**2008**		**2007**	
(Millions of Dollars)					*(Millions of Dollars)*				
CL&P	$	4.8	$	2.3	CL&P	$	18.0	$	11.0
PSNH		-		(1.1) *	PSNH		1.8		(2.1)
WMECO		0.2		(1.4) *	WMECO		0.4		(2.3)
NU parent and other		3.2		2.6	NU parent and other		18.5		15.2
NU consolidated	$	8.2	$	2.4	NU consolidated	$	38.7	$	21.8

*The PSNH and WMECO amounts were reflected in other income, net on the accompanying consolidated statements of income.

Unrecognized Tax Benefits: Upon adoption of FIN 48 on January 1, 2007, NU consolidated, CL&P and PSNH had unrecognized tax benefits totaling $86.1 million, $62.6 million and $0.8 million, respectively, of which $69.5 million, $39.7 million and none, respectively, would impact the effective tax rate, if recognized. WMECO did not have any unrecognized tax benefits upon the adoption of FIN 48 on January 1, 2007. As of December 31, 2008, the portion of unrecognized tax benefits of NU consolidated and CL&P that would impact the effective tax rate, if recognized, were $120 million and $87 million, respectively. As of December 31, 2007, the portion of NU consolidated and CL&P unrecognized tax benefits that would impact the effective tax rate, if recognized, were $93 million and $62.3 million, respectively. As of December 31, 2008 and 2007, there is no such impact for PSNH and WMECO.

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

NU Consolidated

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

		CL&P		PSNH		WMECO
(Millions of Dollars)						
Balance at January 1, 2007	$	62.6	$	0.8	$	-
Gross increases - current year		23.5		-		-
Gross (decreases)/increases - prior year		(10.2)		9.8		2.9
Lapse of statute of limitations		-		-		-
Balance at December 31, 2007		75.9		10.6		2.9
Gross increases - current year		24.9		-		-
Gross increases - prior year		5.6		1.8		0.9
Lapse of statute of limitations		-		-		-
Balance at December 31, 2008	$	106.4	$	12.4	$	3.8

Tax Positions: In September 2008, NU and the IRS reached a settlement agreement related to the timing for deducting certain costs. This agreement closed the federal tax years 2002 through 2004 and resulted in a refund of $123 million less a $35 million payment for 2005. The issues regarding the timing for deducting these costs are also subject to review during the 2005 through 2007 IRS federal audit cycle and therefore are not considered effectively settled for years after 2004. While this settlement resulted in $10.1 million of pre-tax interest income ($6.4 million for CL&P, $1.9 million for PSNH and $1.1 million for WMECO), it did not have a significant impact on income tax expense. NU is currently working to resolve certain tax matters regarding the timing for certain deductions in the open federal tax years. While discussions are currently ongoing with federal and state taxing authorities, it is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. Management estimates that potential resolutions, which are primarily related to timing differences, could result in a $2 million to $42 million decrease in unrecognized tax benefits on an NU consolidated basis, $2 million to $24 million decrease in unrecognized tax benefits by CL&P, zero to $12 million decrease in unrecognized tax benefits by PSNH, and a zero to $4 million decrease in unrecognized tax benefits by WMECO. These estimated changes are related to timing, as well as state tax impacts, which could have an impact on NU consolidated earnings of $1 million to $4 million in 2009. The individual impact from these estimated changes to the 2009 earnings of CL&P, PSNH, and WMECO is not expected to be material.

Tax Years: The following table summarizes NU consolidated, CL&P, PSNH and WMECO's tax years that remain subject to examination by major tax jurisdictions at December 31, 2008:

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

I.

Property, Plant and Equipment and Accumulated Depreciation

The following tables summarize the NU consolidated, CL&P, PSNH, and WMECO investments in utility plant at December 31, 2008 and 2007:

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

	At December 31,	
	2008	**2007**

(Millions of Dollars)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Distribution	$ 3,780.3	$ 1,228.6	$ 625.0	$ 3,559.3	$ 1,128.7	$ 596.3
Transmission	2,464.4	372.4	156.5	1,339.8	291.0	132.4
Generation	-	637.5	-	-	590.5	-
Total property, plant and equipment	6,244.7	2,238.5	781.5	4,899.1	2,010.2	728.7
Less: Accumulated depreciation	1,346.1	771.3	214.7	1,279.7	737.9	205.7
Net property, plant and equipment	4,898.6	1,467.2	566.8	3,619.4	1,272.3	523.0
Construction work in progress	190.5	113.8	57.4	782.4	116.1	36.4
Total property, plant and equipment, net	$ 5,089.1	$ 1,581.0	$ 624.2	$ 4,401.8	$ 1,388.4	$ 559.4

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

In 2008, CL&P, PSNH and WMECO entered into certain equipment purchase contracts that required the company to make advance payments during the design, manufacturing, shipment and installation of equipment. As of December 31, 2008, these advance payments totaled $13.8 million on an NU consolidated basis ($3.6 million for CL&P, $8.9 million for PSNH and $1.3 million for WMECO) and are included in construction work in progress on the accompanying consolidated balance sheets.

The following table summarizes average depreciable lives at December 31, 2008:

	Average Depreciable Life			
(Years)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**
Distribution	33.7	30.3	42.3	33.7
Transmission	59.6	61.4	50.0	58.3
Generation	31.6	-	31.6	-
Competitive energy	5.6	-	-	-
Other	18.0	-	-	-

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

(Percent)	**2008**	**2007**	**2006**
NU Consolidated	3.0	3.2	3.2
CL&P	3.1	3.3	3.5
PSNH	2.7	2.8	2.8
WMECO	2.8	2.9	2.5

J.

Equity Method Investments

Regional Nuclear Companies: At December 31, 2008, CL&P, PSNH and WMECO owned common stock in three regional nuclear companies (Yankee Companies). Each of the Yankee Companies owned a single nuclear generating plant that has been decommissioned. Ownership interests in the Yankee Companies at December 31, 2008, which are accounted for on the equity method, are as follows:

(Percent)	**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
Total NU Consolidated	49.0 %	38.5 %	20.0 %

The total carrying values of ownership interests in CYAPC, YAEC and MYAPC, which are included in deferred debits and other assets - other on the accompanying consolidated balance sheets and the regulated companies - electric distribution reportable segment, are as follows:

(Millions of Dollars)	**2008**	**2007**
CL&P	$ 5.0	$ 4.5
PSNH	0.8	0.8
WMECO	1.4	1.3
Total NU Consolidated	$ 7.2	$ 6.6

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

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

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

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

K.

Allowance for Funds Used During Construction

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

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

	For the Years Ended December 31,								
	2008			**2007**			**2006**		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
AFUDC:									

Borrowed funds	$ 13.0	$ 3.0	$ 1.0	$ 10.9	$ 3.0	$ 1.0	$ 6.6	$ 2.8	$ 0.9
Equity funds	23.2	4.4	1.2	14.2	2.0	0.2	7.6	4.4	0.2
Totals	$ 36.2	$ 7.4	$ 2.2	$ 25.1	$ 5.0	$ 1.2	$ 14.2	$ 7.2	$ 1.1
Average AFUDC rates	8.4%	7.9%	7.6%	8.0%	7.0%	6.1%	7.9%	7.3%	6.8%

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

L.

Sale of Customer Receivables

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

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

In 2007, the transfer of receivables to the financial institution under this arrangement qualified for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities - A Replacement of SFAS No. 125."

M.

Asset Retirement Obligations

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

The fair value of the AROs is recorded as a liability in deferred credits and other liabilities - other with an offset included in property, plant and equipment on the accompanying consolidated balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively. Both the depreciation and accretion were recorded as increases to regulatory assets on the accompanying consolidated balance sheets at December 31, 2008 and 2007.

As the regulated companies are cost-of-service, rate regulated entities, these companies apply regulatory accounting in accordance with SFAS No. 71, and the costs associated with the regulated companies' AROs were included in other regulatory assets at December 31, 2008 and 2007.

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

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

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

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CL&P	At December 31, 2008			
(Millions of Dollars)	ARO Asset	Accumulated Depreciation of ARO Asset	Regulatory Asset	ARO Liabilities
Asbestos	$ 1.6	$ (1.0)	$ 12.0	$ (12.6)
Hazardous contamination	4.1	(1.0)	8.7	(11.8)
Other AROs	3.4	(1.5)	2.4	(4.3)
Total AROs	$ 9.1	$ (3.5)	$ 23.1	$ (28.7)

CL&P	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)

PSNH	At December 31, 2008			
(Millions of Dollars)	ARO Asset	Accumulated Depreciation of ARO Asset	Regulatory Asset	ARO Liabilities
Asbestos	$ 0.9	$ (0.5)	$ 7.1	$ (8.3)
Hazardous contamination	0.5	(0.3)	5.6	(6.3)
Other AROs	-	-	1.2	(1.3)
Total AROs	$ 1.4	$ (0.8)	$ 13.9	$ (15.9)

PSNH	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)

WMECO	At December 31, 2008			
(Millions of Dollars)	**ARO Asset**	**Accumulated Depreciation of ARO Asset**	**Regulatory Asset**	**ARO Liabilities**
Asbestos	$ 0.2	$ (0.1)	$ 1.7	$ (1.8)
Hazardous contamination	0.5	(0.1)	0.9	(1.3)
Other AROs	0.3	(0.2)	0.2	(0.3)
Total AROs	$ 1.0	$ (0.4)	$ 2.8	$ (3.4)

WMECO	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 AROs	$ 1.5	$ (0.5)	$ 2.7	$ (3.7)

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

	At December 31,	
	2008	**2007**
(Millions of Dollars)	**NU Consolidated**	**NU Consolidated**
Balance at beginning of year	$ (49.7)	$ (59.7)
Liabilities incurred during the year	(1.8)	(2.8)
Liabilities settled during the year	3.6	7.3
Accretion	(3.2)	(1.3)
Changes in estimates	-	7.9
Revisions in estimated cash flows	0.5	(1.1)
Balance at end of year	$ (50.6)	$ (49.7)

	At December 31,					
	2008			**2007**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Balance at beginning of year	$ (28.6)	$ (14.9)	$ (3.7)	$ (35.8)	$ (17.3)	$ (4.0)
Liabilities incurred during the year	(1.8)	-	-	(2.8)	-	-
Liabilities settled during the year	3.0	-	0.5	7.1	-	0.2
Accretion	(1.8)	(1.0)	(0.2)	(0.8)	(0.3)	(0.1)
Changes in estimates	-	-	-	4.2	2.9	0.5
Revisions in estimated cash flows	0.5	-	-	(0.5)	(0.2)	(0.3)
Balance at end of year	$ (28.7)	$ (15.9)	$ (3.4)	$ (28.6)	$ (14.9)	$ (3.7)

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

N.

Fuel, Materials and Supplies

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

PSNH is subject to federal and state laws and regulations that regulate emissions of air pollutants, including sulfur dioxide (SO2) and nitrogen oxide (NOx) related to its regulated generation units, and uses SO2 and NOx emissions allowances. At the end of each compliance period, PSNH is required to relinquish SO2 and NOx emissions allowances corresponding to the actual emissions emitted by its generating units over the compliance period. SO2 and NOx emissions allowances are obtained through an annual allocation from the federal and state regulators that are granted at no cost and through purchases from third parties.

SO2 and NOx emissions allowances are recorded as fuel, materials and supplies and are classified on the balance sheet as short-term or long-term depending on the period they are expected to be utilized against actual emissions. At December 31, 2008 and 2007, PSNH had $6.5 million and $3.4 million, respectively, of short-term SO2 and NOx emissions allowances classified as fuel, materials and supplies on the accompanying consolidated balance sheets and $23.5 million and $23.3 million, respectively, of long-term SO2 and NOx emissions allowances classified as deferred debits and other assets - other on the accompanying consolidated balance sheets.

SO2 and NOx emissions allowances are charged to expense based on their weighted average cost as they are utilized against emissions volumes at PSNH s generating units. PSNH recorded expenses of $2.8 million, $5.9 million, and $7.9 million for the years ended December 31, 2008, 2007, and 2006, respectively, which was included in fuel, purchased and net interchange power on the accompanying consolidated income statements. These costs are recovered from ratepayers through PSNH ES revenues. See Note 1G, "Summary of Significant Accounting Policies - Regulatory Accounting" for further information.

O.

Cash and Cash Equivalents

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

P.

Special Deposits and Counterparty Deposits

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

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

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

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

CL&P, PSNH and WMECO had amounts on deposit related to four subsidiaries used to facilitate the issuance of RRBs. In addition, CL&P, PSNH and WMECO had other cash deposits held with unaffiliated parties at December 31, 2008 and 2007. These amounts were as follows:

	At December 31, 2008			
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**
Rate reduction bond deposits	$ 41.3	$ 18.0	$ 19.3	$ 4.0
Other deposits	7.0	5.2	0.9	-

	At December 31, 2007			
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**
Rate reduction bond deposits	$ 43.5	$ 14.3	$ 24.4	$ 4.8
Other deposits	6.4	5.8	0.5	-

These amounts are included in deferred debits and other assets - other on the accompanying consolidated balance sheets.

Q.

Other Taxes

Certain excise taxes levied by state or local governments are collected by CL&P and Yankee Gas from its customers. These excise taxes are accounted for on a gross basis with collections in revenues and payments in expenses. Gross receipts taxes, franchise taxes and other excise taxes were included in operating revenues and taxes other than income taxes on the accompanying consolidated statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**2006**
NU Consolidated	$ 126.6	$ 112.2	$ 114.1
CL&P	107.2	95.0	92.7

Certain sales taxes are also collected by CL&P and Yankee Gas from their customers as agents for state and local governments and are recorded on a net basis with no impact on the accompanying consolidated statements of income.

R.

Other Income, Net

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

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

Investment write-downs		(14.6)		(0.5)		-
Loss on investment in receivables		-		-		(1.1)
Other		(0.3)		(0.2)		(0.2)
Total Other Loss		(14.9)		(0.7)		(1.3)
Total Other Income, Net	$	50.4	$	61.6	$	64.4

CL&P	**For the Years Ended December 31,**		
(Millions of Dollars)	**2008**	**2007**	**2006**
Other Income:			
Investment income	$ 6.0	$ 7.7	$ 9.8
2008 federal tax settlement - interest	6.4	-	-
AFUDC - equity funds	23.2	14.2	7.6
Energy Independence Act incentives	12.1	9.9	5.5
Conservation and load management incentives	3.0	5.5	4.2
Fixed procurement fee	-	-	11.0
Equity in earnings of regional nuclear generating companies	0.3	1.9	(0.9)
Other	0.8	0.7	0.7
Total Other Income	51.8	39.9	37.9
Other Loss:			
Investment write-downs	(9.8)	-	-
Rental investment expenses	(0.1)	(0.1)	(0.1)
Total Other Loss	(9.9)	(0.1)	(0.1)
Total Other Income, Net	$ 41.9	$ 39.8	$ 37.8

PSNH	**For the Years Ended December 31,**		
(Millions of Dollars)	**2008**	**2007**	**2006**
Other Income:			
Investment income	$ 1.9	$ 2.6	$ 1.7
2008 federal tax settlement - interest	1.9	-	-
AFUDC - equity funds	4.4	2.0	4.4
Conservation and load management incentives	1.3	1.7	1.4
Equity in earnings of regional nuclear generating companies	0.1	0.3	(0.1)
Other	0.1	0.1	-
Total Other Income	9.7	6.7	7.4
Other Loss:			
Investment write-downs	(2.4)	-	-
Total Other Loss	(2.4)	-	-
Total Other Income, Net	$ 7.3	$ 6.7	$ 7.4

WMECO	**For the Years Ended December 31,**		
(Millions of Dollars)	**2008**	**2007**	**2006**
Other Income:			
Investment income	$ 1.2	$ 2.7	$ 1.4
2008 federal tax settlement - interest	1.1	-	-
AFUDC - equity funds	1.2	0.2	0.2
Conservation and load management incentives	0.5	0.5	0.9
Equity in earnings of regional nuclear generating companies	0.1	0.5	(0.2)
Total Other Income	4.1	3.9	2.3
Other Loss:			
Investment write-downs	(2.1)	-	-
Total Other Loss	(2.1)	-	-
Total Other Income, Net	$ 2.0	$ 3.9	$ 2.3

Equity in earnings of regional nuclear generating and transmission companies relates to the NU consolidated investment, including CL&P, PSNH and WMECO's investment, in the Yankee Companies and NU s investment in the two Hydro-Québec transmission companies.

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

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

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

S.

Supplemental Cash Flow Information (NU Consolidated)

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

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

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

T.

Operating Expenses

Fuel, purchased and net interchange power: For the years ended December 31, 2008, 2007, and 2006, fuel, purchased and net interchange power included costs related to fuel (and gas costs as it related to Yankee Gas) as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**2006**
CL&P	$ 4.1	$ 14.2	$ 14.1
PSNH	177.4	190.2	156.2

WMECO	0.8	0.8	0.8
Yankee Gas	358.8	317.7	291.3
Other	0.6	1.2	29.8
NU Consolidated	$ 541.7	$ 524.1	$ 492.2

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

U.

Marketable Securities

Supplemental benefit trust and Spent Nuclear Fuel Trust: NU maintains a supplemental benefit trust and WMECO maintains a spent nuclear fuel trust, both of which hold marketable securities. The trusts are used to fund NU s SERP/non-SERP and WMECO s prior period spent nuclear fuel liability. NU and 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, 2008, changes in the fair value of securities in the supplemental benefit trust relating to unrealized losses are considered other than temporary because NU and WMECO do not have the ability to hold the securities to maturity and are recorded as a pre-tax loss. Changes related to unrealized gains are recorded in accumulated other comprehensive income. Realized gains and losses and unrealized losses related to the supplemental benefit trust are included in other income, net, on the consolidated statements of income. Realized gains, net of realized and unrealized losses associated with the WMECO spent nuclear fuel trust are recorded as an offset to the spent nuclear fuel trust obligation.

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

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

V.

Provision for Uncollectible Accounts

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

In November 2006, the DPUC issued an order allowing CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2008, CL&P and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $41 million and $10 million, respectively, with the corresponding bad debt expense recorded as regulatory assets as these amounts are probable of recovery. These regulatory asset amounts are included in CL&P undercollections and write-off of uncollectible hardship receivables for CL&P and Yankee Gas, respectively. At December 31, 2007, these amounts totaled $24 million and $8 million, respectively, and were included in write-off of uncollectible hardship receivables.

For the year ended December 31, 2008, the CL&P and Yankee Gas reserves offset receivables. For the year ended December 31, 2007, the reserve offset amounts sold to CRC by CL&P but not sold to the financial institution. These amounts were classified as investments in securitizable assets on the accompanying consolidated balance sheets. For the year ended December 31, 2007, Yankee Gas reserves offset receivables.

W.

Self-Insurance Accruals

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

X.

Related Parties

Several wholly-owned subsidiaries of NU provide support services for NU and its subsidiaries, including CL&P, PSNH and WMECO. 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.

At both December 31, 2008 and 2007, CL&P, PSNH and WMECO had long-term receivables from NUSCO in the amount of $25 million, $3.8 million and $5.5 million, respectively, which are 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, PSNH and WMECO employees. These amounts have been eliminated in consolidation on the NU consolidated financial statements.

Included in the CL&P, PSNH and WMECO consolidated balance sheets at December 31, 2008 and 2007 are accounts receivable from affiliated companies and accounts payable to affiliated companies relating to transactions between CL&P, PSNH and WMECO and other subsidiaries that are wholly-owned by NU. As of December 31, 2007, CL&P, PSNH and WMECO had $0.3 million, $0.2 million and $0.1 million, respectively, of tax payments accrued in accounts payable to affiliated companies related to the estimated quarterly income tax obligation paid in the following quarter. As of December 31, 2008, PSNH had $0.1 million related to this accrual. CL&P and WMECO had a de minimis balance as of December 31, 2008. These amounts have been eliminated in consolidation on the NU consolidated financial statements.

Total CL&P purchases from Select Energy were $6.1 million for the year ended December 31, 2006. Total WMECO purchases from Select Energy were $0.9 million for the year ended December 31, 2006. There were no such purchases in 2008 or 2007. These amounts have been eliminated in consolidation on the NU consolidated financial statements.

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 easement 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 property, plant and equipment on the accompanying consolidated balance sheet of CL&P as of December 31, 2008 and 2007.

On December 31, 2008, NU's wholly owned subsidiaries, HWP and Holyoke Power and Electric Company (HP&E) transferred $4 million in transmission related assets to WMECO, after certain routine regulatory filings, will cease being subject to FERC.

In 2007, NU and its subsidiaries made aggregate discretionary contributions of $3 million ($0.6 million for CL&P, $0.6 million for PSNH, and $0.1 million for WMECO) to the NU Foundation (Foundation), an independent not-for-profit charitable entity designed to invest in projects that emphasize economic development, workforce training and education, and a clean and healthy environment. In 2008, NU and its subsidiaries did not make any contributions. The board of directors of the Foundation consists of certain NU officers. The Foundation is not included in the consolidated financial statements of NU because the Foundation is a not-for-profit entity and because the company does not have title to the Foundation's assets and cannot receive contributions back from the Foundation. Any donations made to the Foundation negatively impact the earnings of NU and its respective subsidiaries, including CL&P, PSNH and WMECO.

2.

Short-Term Debt (All Companies)

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

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant. In an order dated August 3, 2007, the NHPUC increased the amount of short-term borrowings authorized for PSNH to a maximum of 10 percent of net fixed plant plus $35 million through the earlier of December 31, 2008, or until PSNH utilized its long-term debt authorization. At December 31, 2008, after the expiration of this additional authority, PSNH's short-term debt authorization under the 10 percent of net fixed plant test totaled $146.6 million. As a result of the NHPUC having jurisdiction over PSNH's short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur. In November 2003, CL&P obtained from its preferred stockholders authorization for a ten-year period expiring in March 2014 to issue unsecured indebtedness with a maturity of less than 10 years in excess of the 10 percent of total capitalization limitation in CL&P's preferred stock provisions, provided that all unsecured indebtedness does not exceed 20 percent of total capitalization. As of December 31, 2008, CL&P was permitted to incur $584.4 million of additional unsecured debt under this authorization.

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

Regulated Companies Credit Agreement: CL&P, PSNH, WMECO, and Yankee Gas are parties to a five-year unsecured revolving credit facility in the nominal amount of $400 million that expires on November 6, 2010. CL&P may draw up to $200 million under this facility, with PSNH, WMECO and Yankee Gas able to draw up to $100 million each, subject to the $400 million maximum borrowing limit. This total commitment may be increased to $500 million at the request of the borrowers, subject to lender approval. There were $188 million, $45.2 million, $29.9 million and $52.3 million in short-term borrowings by CL&P, PSNH, WMECO and Yankee Gas, respectively, outstanding under this facility as of December 31, 2008. There were $45 million of long-term borrowings by Yankee Gas outstanding under this facility at December 31, 2007. There were $10 million and $27 million in short-term borrowings by PSNH and Yankee Gas, respectively, outstanding under this facility at December 31, 2007. The weighted-average interest rate on these short-term borrowings on December 31, 2008 and 2007 was 3.35 percent and 7.25 percent, respectively.

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

Under this facility, NU can borrow either on a short-term or a long-term basis. At December 31, 2008, NU had $303.5 million in short-term borrowings outstanding under this facility. At December 31, 2007, there were $42 million in short-term borrowings outstanding under this facility. The weighted-average interest rate on such borrowings outstanding under these credit agreements on December 31, 2008 and 2007 was 3.35 percent and 7.25 percent, respectively. There were $87 million ($85 million for PSNH) and $27 million ($19 million for PSNH) in LOCs outstanding at December 31, 2008 and 2007, respectively.

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

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

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

Amounts outstanding under these credit facilities, excluding the $45 million of long-term borrowings by Yankee Gas at December 31, 2007, are classified as current liabilities as notes payable to banks on the accompanying consolidated balance sheets, as management anticipates that all borrowings under these credit facilities will be outstanding for no more than 364 days at one time.

Pool: CL&P, PSNH, WMECO, Yankee Gas and certain of NU s other companies are members of the Pool. The Pool provides a more efficient use of cash resources of NU and reduces outside short-term borrowings. NUSCO is permitted to borrow from the Pool and administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are 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 of NU, however, bear interest at NU's cost and must be repaid based upon the terms of contributions to NU's original borrowing. On an NU consolidated level, Pool amounts payable or receivable to or from members eliminate in consolidation. At December 31, 2008 and 2007, CL&P, PSNH and WMECO had the following borrowings from/(contributions to) the Pool with the respective weighted average interest rate on borrowings from the Pool for the years ended December 31, 2008 and 2007:

	As of and for the Years Ended December 31,					
		2008			**2007**	
(Millions of Dollars, except percentage)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Borrowings from/(contributions to)	$ 102.7	$ (53.8)	$ 31.6	$ 38.8	$ 11.3	$ 14.9
Weighted average interest rate	1.57 %	2.24 %	2.22 %	5.04 %	5.19 %	5.16 %

3.

Derivative Instruments (NU, CL&P, PSNH, Yankee Gas, Select Energy)

Contracts that are derivatives and do not meet the requirements to be treated as a cash flow hedge or normal purchase or normal sale are recorded at fair value with changes in fair value included in earnings. For those contracts that meet the definition of a derivative and meet the cash flow hedge requirements, including those related to initial and ongoing documentation, the contract is recorded at fair value and the changes in the fair value of the effective portion of those contracts are recognized in accumulated other comprehensive income. Cash flow hedges include forward interest rate swap agreements on proposed debt issuances. When a cash flow hedge is settled, the settlement amount is recorded in accumulated other comprehensive income and is amortized into earnings over the term of the debt. Cash flow hedges impact net income when the hedged items affect earnings, when hedge ineffectiveness is measured and recorded, or when the forecasted transaction being hedged is improbable of occurring. Derivative contracts designated as fair value hedges and the items they are hedging are both recorded at fair value with changes in fair value of both items recognized in earnings. Derivative contracts that meet the requirements of a normal purchase or sale, and are so designated, are recognized in revenues or expenses, as applicable, when the quantity of the contract is delivered.

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

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

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

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

The business activities of NU Enterprises that result in the recognition of derivative assets also create exposures to credit risk of energy marketing and trading counterparties. At December 31, 2008, Select Energy had no derivative assets from wholesale activities that are exposed to counterparty credit risk. The business activities of the regulated companies that resulted in the recognition of derivative assets also create exposure to various counterparties. At December 31, 2008, NU consolidated had $273.2 million ($245.8 million for CL&P and $4.7 million for PSNH) of regulated company and NU parent derivative assets exposed to counterparty credit risk that are contracted with multiple entities, of which $125.5 million ($104.7 million for CL&P) is contracted with investment grade entities, $4.6 million related to PSNH is contracted with a government-backed entity, $131.4 million related to CL&P is contracted with a non-rated subsidiary of an investment grade company and the remainder are contracted with multiple other counterparties.

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

The decision to exit the wholesale marketing business changed management's conclusion regarding the likelihood that these wholesale marketing contracts would result in physical delivery to customers and resulted in a change in the first quarter of 2005 from accrual accounting to mark-to-market accounting for the wholesale marketing contracts. For the years ended December 31, 2008, 2007 and 2006, NU recorded a pre-tax benefit of $7 million and pre-tax charges of $7.4 million and $11.7 million, respectively, in fuel, purchased and net interchange power related to these contracts. In addition, NU recorded a benefit of $1 million to fuel, purchased and net interchange power related to wholesale marketing contracts for the year ended December 31, 2007.

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

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

Regulated Companies - Electric - Supply/Stranded Costs: CL&P has contracts with two IPPs to purchase power that contain pricing provisions that are not clearly and closely related to the price of power and therefore do not qualify for the normal purchases and sales exception. The fair values of these derivatives at December 31, 2008 included short-term and long-term derivative assets with fair values of $20.8 million and $110.6 million, respectively, and short-term and long-term derivative liabilities with fair values of $6.5 million and $65.6 million, respectively. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of stranded costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates. At December 31, 2007, the fair values of these derivatives included short-term and long-term derivative assets with fair values of $53.3 million and $257.9 million, respectively, and short-term and long-term derivative liabilities with fair values of $2.9 million and $28.9 million, respectively.

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

Pursuant to Public Act 05-01, "An Act Concerning Energy Independence," in August 2007, the DPUC approved two CL&P contracts associated with the capacity of two generating projects to be built or modified. The DPUC also approved two capacity-related contracts entered into by The United Illuminating Company (UI), one with a generating project to be built and one with a new demand response project. The total capacity of these four projects is expected to be approximately 787 megawatts (MW). The contracts, referred to as CfDs, obligate the utilities' customers to pay the difference between a set capacity price and the forward capacity market price that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs, with 80 percent allocated to CL&P and 20 percent to UI. The ultimate cost to CL&P under the contracts will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. At December 31, 2008, the fair value of the CL&P CfDs was recorded as a long-term derivative liability of $782.5 million. The fair values of UI's share of CL&P's contracts and CL&P's share of UI's contracts were recorded as a long-term derivative asset of $104.7 million. An offsetting regulatory asset of $677.8 million was recorded, as management believes these amounts will be recovered from or refunded to customers in cost-of-service, regulated rates. The value of CL&P's CfDs at December 31, 2008 included approximately $100 million of initial gains and losses, previously deferred due to the use of significant unobservable inputs in the valuation, that were recorded upon adoption of SFAS No. 157 on January 1, 2008. At December 31, 2007, changes in CfD fair values since inception were recorded as a long-term derivative liability of $107.1 million, and UI's share and one CL&P CfD were recorded as long-term derivative assets of $20.8 million. Offsetting regulatory assets of $86.7 million and regulatory liabilities of $0.4 million were also recorded at December 31, 2007. A 2007 NRG Energy, Inc. (NRG) appeal of the DPUC's decision selecting the CfDs was taken into consideration in valuing the CfDs as of December 31, 2007, reducing the net negative derivative values by approximately $215 million. In February 2008, the appeal was denied, which increased derivative liabilities in 2008.

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

PSNH has a contract to assign its transmission rights in a direct current transmission line in exchange for two energy call options that expire in 2010. These energy call options are derivatives that do not qualify for the normal purchases and sales exception and are accounted for at fair value based on option value modeling. At December 31, 2008, the options were recorded as a short-term and long-term derivative asset of $0.8 million and $3.8 million, respectively, which include mark-to-market losses of $11.1 million in 2008. The initial gain of $13.5 million on this transaction was recorded as a derivative asset and regulatory liability. Short-term and long-term

derivative assets at December 31, 2007 were $3.6 million and $12.1 million, respectively, which include $2.2 million in mark-to-market gains in 2007. An offsetting regulatory liability was recorded, as management believes the benefit of this arrangement will be refunded to customers in rates.

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

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

NU Parent - Interest Rate Hedging: In March 2003, to manage the interest rate characteristics of the company's long-term debt, NU parent entered into a fixed to floating interest rate swap on its $263 million, 7.25 percent fixed rate senior notes that mature on April 1, 2012. Under fair value hedge accounting, the changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in interest expense, which generally offset each other in the consolidated statements of income. The cumulative change in the fair value of the swap and the long-term debt was recorded as a derivative asset and an increase to long-term debt of $20.8 million and $4.2 million at December 31, 2008 and 2007, respectively.

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

4.

Fair Value Measurements (All Companies)

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

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

(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**NU Enterprises**	**Yankee Gas**	**NU Parent**
Derivative Assets:							
Level 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Level 2	20.8	-	-	-	-	-	20.8
Level 3	252.4	245.8	4.7	-	-	1.9	-
Total	$ 273.2	$ 245.8	$ 4.7	$ -	$ -	$ 1.9	$ 20.8
Derivative Liabilities:							
Level 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Level 2	(91.7)	-	(91.7)	-	-	-	-
Level 3	(921.6)	(856.9)	(0.6)	-	(63.9)	(0.2)	-
Total	$ (1,013.3)	$ (856.9)	$ (92.3)	$ -	$ (63.9)	$ (0.2)	$ -
Marketable Securities:							
Level 1	$ 42.1	$ -	$ -	$ 10.3	$ -	$ -	$ 31.8
Level 2	67.1	-	-	45.4	-	-	21.7
Level 3	-	-	-	-	-	-	-
Total	$ 109.2	$ -	$ -	$ 55.7	$ -	$ -	$ 53.5

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

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

	For the Year Ended December 31, 2008				
(Millions of Dollars)	NU Consolidated	CL&P	PSNH	NU Enterprises	Yankee Gas
Derivatives, Net:					
Fair value at January 1, 2008 [1]	$ (511.1)	$ (426.9)	$ 15.7	$ (100.1)	$ 0.2
Net realized/unrealized gains included in:					
Earnings [2]	12.0	-	-	12.0	-
Regulatory assets/liabilities	(138.0)	(128.0)	(11.5)	-	1.5
Purchases, issuances and settlements	(32.1)	(56.2)	(0.1)	24.2	-
Fair value at December 31, 2008	$ (669.2)	$ (611.1)	$ 4.1	$ (63.9)	$ 1.7
Period change in unrealized gains included in earnings relating to items held at December 31, 2008	$ 7.0	$ -	$ -	$ 7.0	$ -

(1)

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

(2)

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

5.

Employee Benefits (All Companies)

A.

Pension Benefits and Postretirement Benefits Other Than Pensions

On December 31, 2006, NU implemented SFAS No. 158, which applies to NU s Pension Plan, SERP, and PBOP Plan and required NU to record the funded status of these plans on the consolidated balance sheets, based on the difference between the projected benefit obligation (PBO) for the Pension Plan and accumulated postretirement benefit obligation (APBO) for the PBOP Plan and the fair value of plan assets. At December 31, 2008, the fair values of plan assets are measured in accordance with SFAS No. 157. SFAS No. 158 requires the additional liability to be recorded with an offset to accumulated other comprehensive income in shareholders equity. This amount is remeasured annually, or as circumstances dictate.

At December 31, 2008 and 2007, NU recorded an after-tax charge/(benefit) totaling $38 million and $(8.6) million, respectively, to accumulated other comprehensive income for its unregulated subsidiaries. However, because the regulated companies are cost-of-service, rate regulated entities under SFAS No. 71, regulatory assets were recorded in the amount of $1.1 billion ($537.7 million - CL&P; $142.9 million - PSNH; $113.5 million - WMECO), and $201.4 million ($72.2 million - CL&P; $50.4 million - PSNH; $8.2 million - WMECO), respectively, as these benefits expense amounts have been and continue to be recoverable in cost-of-service, regulated rates. Regulatory accounting was also applied to the portions of the NUSCO costs that support the regulated companies, as these amounts are also recoverable.

Pension Benefits: NU sponsors a single uniform noncontributory defined benefit retirement plan (Pension Plan) under ERISA covering substantially all regular employees of NU and its subsidiaries. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. NU allocates net periodic pension expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked by the trustee for each subsidiary. The actual investment return for the trust each year is allocated to each of the subsidiaries in proportion to the investment return expected to be earned during the year. NU uses a December 31st measurement date for the Pension Plan. Pension expense/(income) affecting earnings is as follows:

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

Total pension expense, net of amounts capitalized

CL&P	For the Years Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**2006**
Total pension (income)/expense	$ (21.3)	$ (15.6)	$ 0.3
Income capitalized as utility plant	9.4	7.3	0.1
Total pension (income)/expense, net of amounts capitalized	$ (11.9)	$ (8.3)	$ 0.4

PSNH	**For the Years Ended December 31,**		
(Millions of Dollars)	**2008**	**2007**	**2006**
Total pension expense	$ 18.1	$ 19.5	$ 20.8
Expense capitalized as utility plant	(4.2)	(4.8)	(4.8)
Total pension expense, net of amounts capitalized	$ 13.9	$ 14.7	$ 16.0

WMECO	**For the Years Ended December 31,**		
(Millions of Dollars)	**2008**	**2007**	**2006**
Total pension income	$ (6.1)	$ (5.0)	$ (1.3)
Income capitalized as utility plant	2.1	1.9	0.5
Total pension income, net of amounts capitalized	$ (4.0)	$ (3.1)	$ (0.8)

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

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

Pension Plan COLA: On May 4, 2007, NU's Board of Trustees approved a cost of living adjustment (COLA) that increased retiree pension benefits for certain participants in the Pension Plan. The COLA was announced on May 8, 2007 at the annual meeting of NU's shareholders, which resulted in a plan amendment in 2007 and a remeasurement of the Pension Plan's benefit obligation as of May 8, 2007. The COLA increased the Pension Plan's benefit obligation by $40 million and was reflected as a prior service cost and as a decrease in the funded status of the Pension Plan. This amount will be amortized over a 12-year period representing average remaining service lives of employees.

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

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

SERP: NU has maintained a SERP since 1987. The SERP provides its eligible participants who are officers of NU with benefits that would have been provided to them under NU's retirement plan if certain Internal Revenue Code and other limitations were not imposed. NU allocates net periodic SERP benefit costs to its subsidiaries based upon actuarial calculations by participant.

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

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

NU annually funds postretirement costs through external trusts with amounts that have been and will continue to be recovered in rates and that are tax deductible.

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

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

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

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

Benefits paid - excluding lump sum payments						
Benefits paid - lump sum payments	(0.5)	(0.2)	N/A	N/A	-	-
Fair value of plan assets at end of year	$ 1,556.8	$ 2,459.4	N/A	N/A	$ 195.6	$ 278.1
Funded status at December 31st	$ (740.9)	$ 202.5	$ (34.2)	$ (32.1)	$ (240.4)	$ (181.5)

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

	At December 31,					
	Pension Benefits		**SERP Benefits**		**Postretirement Benefits**	
NU Consolidated	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
(Accrued)/prepaid pension	$ (740.9)	$ 202.5	$ -	$ -	$ -	$ -
Other current liabilities	-	-	(2.3)	(2.4)	-	-
Other deferred credits and other liabilities	-	-	(31.9)	(29.7)	-	-
Accrued postretirement benefits	-	-	-	-	(240.4)	(181.5)
CL&P						
(Accrued)/prepaid pension	$ (89.3)	$ 334.8	$ -	$ -	$ -	$ -
Other current liabilities	-	-	(0.1)	(0.1)	-	-
Other deferred credits and other liabilities	-	-	(2.5)	(2.3)	-	-
Accrued postretirement benefits	-	-	-	-	(98.6)	(78.6)
PSNH						
Accrued pension	$ (236.3)	$ (138.3)	$ -	$ -	$ -	$ -
Other deferred credits and other liabilities	-	-	(1.8)	(1.8)	-	-
Accrued postretirement benefits	-	-	-	-	(41.8)	(29.1)
WMECO						

(Accrued)/prepaid pension	$	(3.6)	$	90.0	$	-	$	-	$	-	$	-
Other deferred credits and other liabilities		-		-		(0.7)		(0.6)		-		-
Accrued postretirement benefits		-		-		-		-		(18.1)		(12.7)

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

The accumulated benefit obligation for the Pension Plan was $2 billion ($731.6 million - CL&P; $320.4 million - PSNH; $148.4 million - WMECO) and $2 billion ($723.2 million - CL&P; $308.3 million - PSNH; $145.3 million - WMECO) at December 31, 2008 and 2007, respectively, and was $32.1 million ($2.3 million - CL&P; $1.7 million - PSNH; $0.7 million - WMECO) and $30.2 million ($2.2 million - CL&P; $1.6 million - PSNH; $0.6 million - WMECO) for the SERP at December 31, 2008 and 2007, respectively.

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

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

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

NU Consolidated **Estimated Expense in 2009**

	Pension	SERP	PBOP
Transition obligation	$ 0.3	$ -	$ 11.3
Prior service cost	9.5	0.1	0.3
Net actuarial loss	20.6	0.5	9.8
Total	$ 30.4	$ 0.6	$ 21.4

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

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

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

	Estimated Expense in 2009		
NU Consolidated	**Pension**	**SERP**	**PBOP**
Transition obligation	$ -	$ -	$ 0.2
Prior service cost	0.3	-	-
Net actuarial loss	-	-	0.2
Total	$ 0.3	$ -	$ 0.4

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

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

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

Total - net periodic expense	$ 2.4	$ 17.1	$ 50.2	$ 3.1	$ 3.6	$ 4.1	$ 36.2	$ 38.4	$ 48.8
CL&P - net periodic (income)/expense	$ (21.3)	$ (15.6)	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 15.7	$ 16.1	$ 20.1
PSNH - net periodic expense	$ 18.1	$ 19.5	$ 20.8	$ 0.2	$ 0.4	$ 0.2	$ 7.1	$ 7.9	$ 10.1
WMECO - net periodic (income)/expense	$ (6.1)	$ (5.0)	$ (1.3)	$ 0.1	$ 0.1	$ 0.1	$ 2.8	$ 3.0	$ 4.1

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**		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Discount rate	6.60 %	5.95 %[1]	5.80 %	6.35 %	5.80 %	5.65 %
Expected long-term rate of return	8.75 %	8.75 %	8.75 %	N/A	N/A	N/A
Compensation/progression rate	4.00 %	4.00 %	4.00 %	N/A	N/A	N/A
Expected long-term rate of return -						
Health assets, net of tax	N/A	N/A	N/A	6.85 %	6.85 %	6.85 %
Life assets and non-taxable health assets	N/A	N/A	N/A	8.75 %	8.75 %	8.75 %

[1] The 2007 discount rate for the SERP was 5.9 percent.

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

	Year Following December 31,	
	2008	**2007**
Health care cost trend rate assumed for next year	8.00 %	8.50 %
Rate to which health care cost trend rate is assumed to decline (the ultimate trend rate)	5.00 %	5.00 %

Year that the rate reaches the ultimate trend rate	2015	2015

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

NU Consolidated	**One Percentage Point Increase**	**One Percentage Point Decrease**
Effect on total service and interest cost components	$ 1.0	$ (0.8)
Effect on postretirement benefit obligation	11.4	(10.0)

NU s investment strategy for its Pension Plan and PBOP Plan is to maximize the long-term rate of return on those plans assets within an acceptable level of risk. The investment strategy establishes target allocations, which are routinely reviewed and periodically rebalanced. NU s expected long-term rates of return on Pension Plan assets and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, NU also evaluated input from actuaries and consultants, as well as long-term inflation assumptions and NU s historical 25-year compounded return of over 11 percent. The Pension Plan s and PBOP Plan s target asset allocation assumptions and expected long-term rate of return assumptions by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
	2008 and 2007		2008 and 2007	
Asset Category	**Target Asset Allocation**	**Assumed Rate of Return**	**Target Asset Allocation**	**Assumed Rate of Return**
Equity Securities:				
United States	40%	9.25%	55%	9.25%
Non-United States	17%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	2%	10.25%
Private	8%	14.25%	-	-
Debt Securities:				
Fixed income	25%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%
Real Estate	5%	7.50%	-	-

The actual asset allocations at December 31, 2008 and 2007 approximated these target asset allocations. The plans actual weighted-average asset allocations by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
Asset Category	**2008**	**2007**	**2008**	**2007**
Equity Securities:				
United States	34%	40%	57%	55%
Non-United States	16%	17%	12%	14%
Emerging markets	4%	5%	1%	1%
Private	11%	7%	-	-

Debt Securities:				
Fixed income	29%	26%	29%	29%
High yield fixed income	-	-	1%	1%
Real Estate	6%	5%	-	-
Totals	100%	100%	100%	100%

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

	Pension Benefits	SERP Benefits	Postretirement Benefits	Government Benefits
NU Consolidated				
2009	$ 124.1	$ 2.3	$ 43.2	$ (3.9)
2010	128.9	2.5	43.9	(4.2)
2011	132.4	2.7	44.2	(4.6)
2012	136.0	2.9	44.3	(5.0)
2013	140.8	3.1	44.6	(5.3)
2014-2018	805.1	17.4	224.8	(31.3)

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

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

For the PBOP Plan, it is currently NU's policy to annually fund an amount equal to the PBOP Plan s postretirement benefit cost, excluding curtailment and termination benefits. NU contributed $36.2 million for the year ended December 31, 2008 to fund the PBOP Plan and expects to make $37.3 million in contributions to the PBOP Plan in 2009. Beginning in 2007, NU made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $3.7 million in 2008 and is estimated to be $3.4 million in 2009.

B.

Defined Contribution Plans

NU maintains a 401(k) Savings Plan for substantially all NU employees, including CL&P, PSNH and 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 allocated from the Employee Stock Ownership Plan (ESOP). The 401(k) matching contributions of cash and NU common shares made by NU were $12 million ($4 million for CL&P, $2.3 million for PSNH and $0.7 million for WMECO) in 2008, $10.7 million ($3.6 million for CL&P, $2.2 million for PSNH and $0.7 million for WMECO) in 2007, and $11 million ($3.6 million for CL&P, $2.1 million for PSNH and $0.7 million for WMECO) in 2006.

Effective on January 1, 2006, all newly hired, non-bargaining unit employees, and effective on January 1, 2007 or as subject to collective bargaining agreements, certain newly hired bargaining unit employees participate in a new program under the 401(k) savings plan called the K-Vantage benefit. These employees are not eligible to participate in the existing defined benefit Pension Plan. In addition, participants in the Pension Plan at January 1, 2006 were given the opportunity to choose to become a participant in the K-Vantage benefit beginning in 2007, in which case their benefit under the Pension Plan would be frozen. NU makes contributions to the K-Vantage benefit based on a percentage of participants' eligible compensation, as defined by the benefit document. The contributions made by NU were $2 million ($173 thousand for CL&P, $276 thousand for PSNH and $20 thousand for WMECO) in 2008, $1 million ($71 thousand for CL&P, $139 thousand for PSNH and $9 thousand for WMECO) in 2007 and $0.1 million ($6 thousand for CL&P, $23 thousand for PSNH and $2 thousand for WMECO) in 2006.

C.

Employee Stock Ownership Plan

NU maintains an ESOP for purposes of allocating shares to NU, CL&P, PSNH, and WMECO's employees participating in NU s 401(k) Savings Plan. Under this arrangement, NU issued unsecured notes during 1991 and 1992 totaling $250 million, the proceeds of which were loaned to the ESOP trust (ESOP Notes) for the purchase of 10.8 million newly issued NU common shares (ESOP shares). The ESOP trust is obligated to make principal and interest payments to NU on the ESOP Notes at the same rate that ESOP shares are allocated to employees. Through December 31, 2008, NU made annual contributions to the ESOP trust equal to the ESOP s debt service, less dividends received by the ESOP. NU s contributions to the ESOP trust totaled $6 million in 2008, $4.2 million in 2007 and $8.2 million in 2006. Interest expense on the unsecured notes was $3.2 million in 2006. For the years ended December 31, 2008, 2007 and 2006, NU recognized $8 million, $6.9 million and $7.4 million, respectively, of expense related to the ESOP, excluding the interest expense on the unsecured notes. The $75 million Series B note was fully repaid in March 2005. The $175 million Series A note was fully repaid in December 2006. As a result, no further interest expense is being incurred for the ESOP.

All dividends received by the ESOP on unallocated shares were used to pay debt service through December 31, 2006. Dividends on the ESOP unallocated shares are not considered dividends for financial reporting purposes. During the first and second quarters of 2007, NU paid a $0.1875 per share quarterly dividend. During the third quarter of 2007 through the second quarter of 2008, NU paid a $0.20 per share quarterly dividend. NU paid a $0.2125 per share dividend during the third and fourth quarters of 2008.

In 2008 and 2007, the ESOP trust allocated 469,601 and 363,470 of NU common shares, respectively, to satisfy 401(k) Savings Plan obligations to employees. At December 31, 2008 and 2007, total allocated ESOP shares were 10,130,407 and 9,660,806, respectively, and total unallocated ESOP shares were 669,778 and 1,139,379, respectively. The fair market value of the unallocated ESOP shares at December 31, 2008 and 2007 was $16.1 million and $35.7 million, respectively.

D.

Share-Based Payments

NU maintains an Employee Share Purchase Plan (ESPP) and other long-term equity-based incentive plans under the Northeast Utilities Incentive Plan (Incentive Plan) in which NU, CL&P, PSNH and WMECO employees and officers are entitled to participate. NU, CL&P, PSNH and WMECO record compensation cost related to these plans, as applicable, for shares issued or sold to NU, CL&P, PSNH and WMECO 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, PSNH and 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 NU, CL&P, PSNH and WMECO s financial statements and no effect on NU's EPS. For the years ended December 31, 2008 and 2007, tax expense in excess of compensation cost totaling $1.6 million and $3.2 million, respectively, increased cash flows from financing activities.

SFAS No. 123(R) requires that share-based payments be recorded using the fair value-based method based on the fair value at the date of grant and applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed.

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

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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.

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Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.

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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.

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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, PSNH and WMECO participate, NU is authorized to grant up to 4.5 million new shares for various types of awards, including restricted shares, RSUs, performance units and stock options to eligible employees and board members. At December 31, 2008 and 2007, NU had 2,705,615 and 3,055,083 of common shares, respectively, available for issuance under the Incentive Plan.

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

The total compensation cost recognized on an NU consolidated basis for restricted shares was $12 thousand, net of taxes of approximately $8 thousand for the year ended December 31, 2008, $58 thousand, net of taxes of approximately $39 thousand for the year ended December 31, 2007, and $0.6 million, net of taxes of approximately $0.4 million for the year ended December 31, 2006. In 2008, 2007 and 2006, the compensation cost had a de minimis impact to CL&P, PSNH and WMECO.

RSUs: NU has granted RSUs under the 2004 through 2008 incentive programs that are subject to three-year and four-year graded vesting schedules for employees, and one-year graded vesting schedules for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of RSU transactions for the year ended December 31, 2008 is as follows:

RSUs	**RSUs (Units)**	**Weighted Average Grant - Date Fair Value**	**Total Grant - Date Fair Value (Millions)**	**Remaining Compensation Cost (Millions)**	**Weighted Average Remaining Period (Years)**
Outstanding at December 31, 2007	831,000	$22.99			
Granted	352,482	$26.82	$ 9.5		
Issued	(263,422)	$21.94	$ 5.8		
Forfeited	(7,069)	$25.97	$ 0.2		
Outstanding at December 31, 2008	912,991	$24.75	$22.6	$9.0	2.0

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

The total compensation cost recognized on an NU consolidated basis (by CL&P, PSNH and WMECO) for RSUs was $3.9 million ($2.4 million, $716 thousand and $407 thousand), net of taxes of approximately $2.6 million ($1.6 million, $478 thousand and $271 thousand) for the year ended December 31, 2008, $3.6 million ($2.3 million, $586 thousand and $387 thousand), net of taxes of approximately $2.4 million ($1.5 million, $391 thousand and $258 thousand) for the year ended December 31, 2007 and $2.8 million ($1.6 million, $440 thousand and $271 thousand), net of taxes of approximately $1.9 million ($1 million, $290 thousand and $181 thousand) for the year ended December 31, 2006.

Stock Options: Prior to 2003, NU granted stock options to certain employees. These options were fully vested as of December 31, 2005. The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average remaining contractual lives for the options outstanding at December 31, 2008 is 2.4 years. A summary of stock option transactions is as follows:

		Exercise Price Per Share				
	Options	**Range**			**Weighted Average**	**Intrinsic Value**
						(Millions)
Outstanding and exercisable - December 31, 2005	1,122,541	$14.9375	-	$22.2500	$18.4484	
Exercised	(331,943)				$18.3579	$2.0
Forfeited and cancelled	(18,750)				$20.8885	
Outstanding and exercisable - December 31, 2006	771,848	$14.9375	-	$22.2500	$18.4245	
Exercised	(372,168)				$18.5005	$4.8
Forfeited and cancelled	(2,500)				$21.0300	
Outstanding and exercisable - December 31, 2007	397,180	$14.9375	-	$21.0300	$18.3369	
Exercised	(76,260)				$16.2473	$0.6
Forfeited and cancelled	-				-	
Outstanding and exercisable - December 31, 2008	320,920	$14.9375	-	$21.0300	$18.8335	$1.7

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

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

During 2008 and 2007, employees purchased 31,250 and 26,451 shares, respectively, at discounted prices of $26.40 and $23.90 in 2008 and $26.27 and $25.97 in 2007. At December 31, 2008 and 2007, 1,010,114 and 1,041,364 shares remained available for future issuance under the ESPP, respectively.

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

E.

Other Retirement Benefits

NU provides benefits for retirement and other benefits for certain current and past company officers. The actuarially-determined liability for these benefits, which is included in deferred credits and other liabilities - other on the accompanying consolidated balance sheets, was $45.4 million and $46.4 million at December 31, 2008 and 2007, respectively. During 2008, 2007 and 2006, $3.8 million, $8.4 million and $5.6 million, respectively, was expensed related to these benefits. These benefits are accounted for on an accrual basis and expensed over the service lives of the employees in accordance with the Accounting Principles Board Opinion (APB) No. 12, "Deferred Compensation Contracts."

6.

Goodwill and Other Intangible Assets (Yankee Gas)

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

NU s reporting units are consistent with the operating segments underlying the reportable segments identified in Note 17, "Segment Information," to the consolidated financial statements. The only reporting unit that maintains goodwill is the Yankee Gas reporting unit, which was classified under the regulated companies - gas reportable segment. The goodwill recorded related to the acquisition of Yankee Gas is not being recovered from the customers of Yankee Gas. The goodwill balance held by the Yankee Gas reporting unit at December 31, 2008 and 2007 is $287.6 million.

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

7.

Commitments and Contingencies

A.

Regulatory Developments and Rate Matters (CL&P, Yankee Gas, PSNH, WMECO)

Connecticut:

CTA and SBC Reconciliation: The CTA allows CL&P to recover stranded costs, such as securitization costs associated with its RRBs, amortization of regulatory assets, and IPP over-market costs, while the SBC allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes, and displaced worker protection costs.

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

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

Procurement Fee Rate Proceedings: CL&P was allowed to collect a fixed procurement fee of 0.50 mills per kilowatt-hour (KWH) from customers that purchased TSO service from 2004 through the end of 2006. One mill is equal to one tenth of a cent. In prior years, CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its transition service procurement fee, which was effective through 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. CL&P has not recorded amounts related to the 2005 or 2006 procurement fee in earnings. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. On January 15, 2009, the DPUC issued a final decision confirming its December 2008 draft decision in this docket that reversed its December 2005 draft decision and stated that CL&P was not eligible for the procurement incentive compensation for 2004. A $5.8 million pre-tax charge was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers has been established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

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

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

New Hampshire:

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

Massachusetts:

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

B.

Environmental Matters (CL&P, PSNH, WMECO, HWP)

General: NU, CL&P, PSNH and WMECO are 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, CL&P, PSNH and WMECO have an active environmental auditing and training program and believe that they are 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, CL&P, PSNH and 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, 2008, NU Consolidated, CL&P, PSNH and WMECO had $27.4 million, $2.8 million, $5.5 million and $0.3 million, respectively, and at December 31, 2007, $25.8 million, $2.9 million, $5.5 million and $0.3 million, respectively, recorded as environmental reserves. A table of the activity in these reserves at December 31, 2008 and 2007 is as follows:

(Millions of Dollars)	NU Consolidated	CL&P	PSNH	WMECO
Balance at December 31, 2006	$ 26.8	$ 2.8	$ 5.6	$ 0.3
Additions	1.2	0.6	0.2	0.3
Payments	(2.2)	(0.5)	(0.3)	(0.3)
Balance at December 31, 2007	25.8	2.9	5.5	0.3
Additions	4.6	0.2	0.6	0.5
Payments	(3.0)	(0.3)	(0.6)	(0.5)
Balance at December 31, 2008	$ 27.4	$ 2.8	$ 5.5	$ 0.3

As of December 31, 2008, the status of environmental sites are as follows:

(Number of Sites)	NU Consolidated	CL&P	PSNH	WMECO
Environmental reserve	54	14	17	9
Remediation or long-term monitoring phase	27	4	11	7
Some site assessments completed	22	9	2	2
Preliminary site assessment stage	5	1	4	-

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. NU, CL&P, PSNH and WMECO have not recorded any probable recoveries from third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

At December 31, 2008, in addition to the 54 sites (14 for CL&P, 17 for PSNH and 9 for WMECO), there were 10 sites (5 for CL&P, 2 for PSNH and 1 for WMECO) for which there are unasserted claims; however, any related site assessment or remediation costs are not probable or estimable at this time. NU, CL&P, PSNH and 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.

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

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

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

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

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

MGP Sites: MGP sites comprise the largest portion of the environmental liabilities. MGPs are sites that manufactured gas from coal that produced certain byproducts that may pose a risk to human health and the environment. At December 31, 2008 and 2007, $25.4 million and $23.6 million ($1.5 million and $1.5 million for CL&P, $4.8 million and $4.7 million for PSNH and $0.1 million and $0.2 million for WMECO), respectively, represent amounts for the site assessment and remediation of MGPs. At December 31, 2008 and 2007, the 5 (1 for PSNH) largest MGP sites comprise approximately 63 percent and 68 percent (76 percent and 94 percent for PSNH), respectively, of the total MGP environmental liability.

For 7 of the 54 sites (3 of the 14 for CL&P, 2 of the 17 for PSNH and 1 of the 9 for WMECO) that are included in the company s liability for environmental costs, the information known and nature of the remediation options at those sites allow for the company to estimate the range of losses for environmental costs. At December 31, 2008, $5.1 million ($1.8 million for CL&P, $0.7 million for PSNH and $0.1 million for WMECO) had been accrued as a liability for these sites, which represent management s best estimates of the liabilities for environmental costs. These amounts are the best estimates within estimated ranges of losses from zero to $11 million ($1.6 million to $6 million for CL&P, zero to $4.2 million for PSNH and zero to $8.8 million for WMECO). For the 47 remaining sites (11 for CL&P, 15 for PSNH and 8 for WMECO) included in the environmental reserve, determining an estimated range of loss is not possible at this time.

CERCLA Matters: The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and its amendments or state equivalents impose joint and several strict liabilities, regardless of fault, upon generators of hazardous substances resulting in removal and remediation costs and environmental damages. Liabilities under these laws can be material and in some instances may be imposed without regard to fault or for past acts that may have been lawful at the time they occurred. Of the 54 sites (14 for CL&P, 17 for PSNH and 9 for WMECO), 5 (1 for CL&P, 3 for PSNH and 1 site having both CL&P and WMECO involved as a party) are superfund sites under CERCLA for which the company has been notified that it is a potentially responsible party (PRP) but for which the site assessment and remediation are not being managed by the company. At December 31, 2008, a liability of $0.7 million ($0.4 million for CL&P, $0.3 million for PSNH and $31 thousand for WMECO) accrued on these sites represents management's best estimate of its potential remediation costs with respect to these 5 (1 for CL&P, 3 for PSNH and 1 site having both CL&P and WMECO involved as a party) 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 (CL&P, WMECO)

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

The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Spent Nuclear Fuel) for CL&P and WMECO, an accrual has been recorded for the full liability, and payment must be made by CL&P and WMECO to the DOE prior to the first delivery of spent fuel to the DOE. After the sale of Millstone, CL&P and WMECO remained responsible for their share of the disposal costs associated with the Prior Period Spent Nuclear Fuel. Until such payment to the DOE is made, the outstanding liability will continue to accrue interest at the 3-month treasury bill yield rate. At December 31, 2008 and 2007, fees due to the DOE for the disposal of Prior Period Spent Nuclear Fuel for the year ended December 31, 2008 and 2007, respectively, are included in long-term debt and were $298.6 million and $294.3 million ($243 million and $238.7 million for CL&P and $55.6 million and $55.6 million for WMECO), respectively, including accumulated interest costs of $217.9 million and $212.6 million ($176.5 million and $172.2 million for CL&P and $41.4 million and $40.4 million for WMECO), respectively.

During 2004, WMECO established a trust that holds marketable securities to fund amounts due to the DOE for the disposal of WMECO s Prior Period Spent Nuclear Fuel. For further information on this trust, see Note 9, "Marketable Securities," to the consolidated financial statements.

D.

Long-Term Contractual Arrangements (NU, CL&P, PSNH, WMECO, Yankee Gas, NU Enterprises)

Regulated Companies:

Estimated Future Annual Regulated Companies Costs: The estimated future annual costs of the regulated companies' significant long-term contractual arrangements at December 31, 2008 are as follows:

NU Consolidated

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

CL&P

(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Totals**
VYNPC	$ 18.0	$ 17.6	$ 17.9	$ 4.3	$ -	$ -	$ 57.8
Supply/stranded cost contracts	171.1	160.5	225.1	227.5	222.8	662.2	1,669.2
Renewable energy contracts	2.8	36.8	64.6	119.0	118.9	1,667.5	2,009.6
Peaker CfDs	-	5.2	15.0	21.6	20.8	35.5	98.1
Hydro-Québec support commitments	11.6	11.7	11.8	11.6	11.4	78.1	136.2
Transmission segment project commitments	145.6	148.5	137.7	129.3	48.0	-	609.1
Yankee Companies billings	17.5	19.2	20.3	20.4	20.1	35.2	132.7
Vehicle/equipment commitments	1.3	1.4	20.2	-	-	-	22.9
Totals	$ 367.9	$ 400.9	$ 512.6	$ 533.7	$ 442.0	$ 2,478.5	$ 4,735.6

PSNH

(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Totals**
VYNPC	$ 7.6	$ 7.4	$ 7.6	$ 1.8	$ -	$ -	$ 24.4
Supply/stranded cost contracts	59.6	59.9	34.5	33.5	29.7	172.3	389.5
Wood, coal and transportation contracts	141.5	87.6	82.5	56.1	-	-	367.7
PNGTS pipeline commitments	2.1	2.0	2.0	2.0	2.0	7.9	18.0
Hydro-Québec support commitments	6.2	6.3	6.3	6.3	6.1	42.0	73.2
Transmission segment project commitments	18.1	5.0	-	-	-	-	23.1
Yankee Companies billings	3.4	3.6	3.8	3.8	3.7	5.5	23.8
Clean air project commitments	76.3	75.3	36.3	16.4	5.1	-	209.4
Vehicle/equipment commitments	13.0	-	-	-	-	-	13.0
Totals	$ 327.8	$ 247.1	$ 173.0	$ 119.9	$ 46.6	$ 227.7	$ 1,142.1

WMECO

(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Totals**
VYNPC	$ 4.7	$ 4.6	$ 4.7	$ 1.1	$ -	$ -	$ 15.1

Supply/stranded cost contracts	2.3	2.3	-	-	-	-	4.6
Transmission segment project commitments	22.9	2.5	15.7	1.8	-	-	42.9
Hydro-Québec support commitments	2.4	2.5	2.5	2.4	2.4	16.4	28.6
Yankee Companies billings	4.8	5.2	5.6	5.6	5.6	9.7	36.5
Vehicle/equipment commitments	0.2	0.3	4.5	-	-	-	5.0
Totals	$ 37.3	$ 17.4	$ 33.0	$ 10.9	$ 8.0	$ 26.1	$ 132.7

VYNPC: NU consolidated, CL&P, PSNH and WMECO have commitments to buy approximately 16 percent, 9.5 percent, 4 percent and 2.5 percent, respectively of the Vermont Yankee Nuclear Power Corporation (VYNPC) plant s output through March 2012 at a range of fixed prices. NU consolidated, CL&P, PSNH and WMECO's total cost of purchases under contracts with VYNPC amounted to $26.5 million, $15.7 million, $6.6 million and $4.2 million, respectively, in 2008, $25.6 million, $15.2 million, $6.4 million and $4 million, respectively, in 2007 and $32.2 million, $19.1 million, $8.1 million and $5 million, respectively, in 2006.

Supply/Stranded Cost Contracts: CL&P, PSNH and WMECO have entered into various IPP contracts that extend through 2024 for CL&P, 2023 for PSNH and 2010 for WMECO for the purchase of electricity, including payment obligations resulting from the buydown of electricity purchase contracts. The total cost of purchases and obligations under these contracts amounted to $237.6 million ($200.5 million for CL&P, $34.6 million for PSNH and $2.5 million for WMECO) in 2008, $281.5 million ($206 million for CL&P, $72.9 million for PSNH and $2.6 million for WMECO) in 2007 and $331.9 million ($206.1 million for CL&P, $123.6 million for PSNH and $2.1 million for WMECO) in 2006. The majority of the contracts expire by 2014 for CL&P and 2018 for PSNH.

In addition, CL&P and UI have entered into four CfDs for a total of approximately 787 MW of capacity with three generation projects to be built or modified and one new demand response project. The CfDs extend through 2026 and obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets. The contracts have terms of up to 15 years beginning in 2009 and are subject to a sharing agreement with UI, whereby UI will share 20 percent of the costs and benefits of these contracts. The information in the table above includes 100 percent of the payments projected under the contracts entered into by CL&P and 80 percent of the payments projected under the contracts entered into by UI, are subject to changes in capacity prices that the projects receive in the ISO-NE capacity markets and CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

These amounts do not include contractual commitments related to CL&P s standard or last resort service or WMECO s default service, both of which represent contractual commitments that are conditional upon CL&P and WMECO customers' use of energy, and PSNH s short-term power supply management.

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

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

Natural Gas Procurement Contracts: Yankee Gas has entered into long-term contracts for the purchase of a specified quantity of natural gas in the normal course of business as part of its portfolio of supplies to meet its actual sales commitments. These contracts extend through 2022. The total cost of Yankee Gas procurement portfolio, including these contracts, amounted to $352.5 million in 2008, $305.3 million in 2007 and $275.1 million in 2006.

Wood, Coal and Transportation Contracts: PSNH has entered into various arrangements for the purchase of wood, coal and the transportation services for fuel supply for its electric generating assets in 2009. PSNH s fuel and natural gas costs, excluding emissions allowances, amounted to approximately $165.4 million in 2008, $183.8 million in 2007 and $149.1 million in 2006.

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

Hydro-Québec Support Commitments: Along with other New England utilities, CL&P, PSNH and WMECO have entered into agreements to support transmission and terminal facilities that were built to import electricity from the Hydro-Québec system in Canada. CL&P, PSNH and WMECO are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual O&M expenses and capital costs of those facilities. NU consolidated, CL&P, PSNH and WMECO's total cost of these agreements amounted to $18.3 million, $10.5 million, $5.6 million and $2.2 million, respectively, in 2008, $18.8 million, $10.8 million, $5.8 million and $2.2 million, respectively, in 2007, and $20.5 million, $11.7 million, $6.4 million and $2.4 million, respectively, in 2006.

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

Yankee Companies Billings: NU consolidated, CL&P, PSNH and WMECO have 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, CL&P, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. The table of estimated future annual regulated companies costs includes the estimated decommissioning and closure costs for CYAPC, YAEC and MYAPC.

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

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Clean Air Project Commitments: These amounts represent commitments for engineering, program management services and major component supply and installation associated with PSNH's coal-fired 440 MW Merrimack Station clean air project, which also includes the addition of a wet scrubber to reduce mercury and SO2 emissions at Merrimack Station Units 1 and 2. The total cost under these contracts amounted to $20.5 million in 2008, $1.9 million in 2007 and $0.9 million in 2006.

Vehicle/Equipment Commitments: CL&P, PSNH, WMECO and Yankee Gas have remaining obligations under master lease agreements that were terminated by the lessor in November 2008. As a result of the termination, in accordance with the lease agreements, remaining vehicle/equipment balances are required to be paid by November 2009 for PSNH totaling $13 million and by January 2011 for CL&P, WMECO, and Yankee Gas totaling $32 million. At the end of the lease, the lessee company will either purchase the vehicle/equipment or sell it at auction with the balances paid to the lessor.

NU Enterprises:

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

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

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

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

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

E.

Deferred Contractual Obligations (CL&P, PSNH, WMECO)

CL&P, PSNH and WMECO have decommissioning and plant closure cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, PSNH and WMECO. These companies recover these costs through state regulatory commission-approved retail rates.

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

CYAPC, YAEC and MYAPC are currently collecting amounts that we believe are adequate to recover the remaining decommissioning and closure cost estimates for the respective plants. We believe CL&P and WMECO will recover their shares of these decommissioning and closure obligations from their customers. PSNH has recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. In December 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

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

The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the

FERC. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, NU does believe that any net settlement proceeds it receives would be incorporated into FERC-approved recoveries, which would be passed on to its customers, through reduced charges.

F.

Guarantees and Indemnifications (All Companies)

NU provides credit assurances on behalf of subsidiaries, including CL&P, PSNH and WMECO, in the form of guarantees and LOCs in the normal course of business. NU has also provided guarantees and various indemnifications on behalf of external parties as a result of the sales of SESI, NU Enterprises' retail marketing business and its competitive generation business. The following table summarizes NU and its subsidiaries' maximum exposure at December 31, 2008, in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," expiration dates, and fair value of amounts recorded.

Company	Description	Maximum Exposure (in millions)		Expiration Date(s)
On behalf of external parties:				
SESI	General indemnifications in connection with the sale of SESI including completeness and accuracy of information provided, compliance with laws, and various claims	Not Specified	(1)	None
	Specific indemnifications in connection with the sale of SESI for estimated costs to complete or modify specific projects (2)	Not Specified	(1)	Through project completion
	Indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts (3)	$1.3		2017-2018
	Surety bonds covering certain projects	$10.5		Through project completion
Hess Corporation (Retail Marketing Business)	General indemnifications in connection with the sale including compliance with laws, completeness and accuracy of information provided and various claims	Not Specified	(1)	None
Energy Capital Partners (Competitive Generation Business)	General indemnifications in connection with the sale of NGC and the generating assets of Mt. Tom including compliance with tax and environmental laws, and various claims	Not Specified	(1)	2008-2009
On behalf of subsidiaries:				

CL&P	Surety bonds (4)	$3.2		2009-2010
PSNH	Surety bonds (4)	$3.9		2009-2010
	Letters of credit	$85.0		2009-2010
WMECO	Surety bonds (4)	$3.0		2009
HWP	Surety bonds (4)	$1.0		2009
NAESCO	Surety bonds (4)	$1.6		2009
RRR	Lease payments for real estate	$9.2		2024
NUSCO	Surety bonds (4)	$1.0		2009
	Lease payments for fleet of vehicles	$8.0		None
	Lease payments for real estate	$1.8		2019
Boulos	Surety bonds covering ongoing projects	$34.1		Through project completion
NGS	Performance guarantee and insurance bonds	$20.4	(5)	2020 (5)
Select Energy	Performance guarantees and surety bonds for retail marketing contracts	$3.3	(6)	None (7)
	Performance guarantees for wholesale contracts	$17.1	(6)	2013
	Letters of credit	$2.0		2009
Other - CYAPC	Surety bonds (4)	$0.3		2010

(1)

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

(2)

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

(3)

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

(4)

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

(5)

Included in the maximum exposure is $19.2 million related to a performance guarantee of NGS's obligations for which there is no specified maximum exposure in the agreement. The maximum exposure is calculated as of December 31, 2008 based on limits of NGS's liability contained in the underlying service contract and assumes that NGS will perform under that contract through its expiration in 2020. The remaining $1.2 million of maximum exposure relates to insurance bonds with no expiration date that are billed annually on their anniversary date.

(6)

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

(7)

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

CL&P, PSNH and WMECO have 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.

NRG Energy, Inc. Exposures (CL&P, Yankee Gas)

Certain subsidiaries of NU, including CL&P and Yankee Gas, entered into transactions with NRG and certain of its subsidiaries. On May 14, 2003, NRG and certain subsidiaries of NRG filed voluntary bankruptcy petitions, and on December 5, 2003, NRG emerged from bankruptcy. NU's NRG-related exposures as a result of these transactions, among other things now resolved, relate to the recovery of approximately $30.2 million of CL&P's station service billings from NRG, and the recovery of, among other claimed damages, approximately $17.5 million of capital costs and expenses incurred by Yankee Gas related to an NRG subsidiary's generating plant construction project that has ceased.

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

H.

Consolidated Edison, Inc. Merger Litigation (NU)

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

I.

Other Litigation and Legal Proceedings (All Companies)

NU and its subsidiaries (including CL&P, PSNH and WMECO) are involved in other legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, which involve management s assessment to determine the probability of whether a loss will occur and, if probable, its best estimate of probable loss as defined by SFAS No. 5. The company records and discloses losses when these losses are probable and reasonably estimable in accordance with SFAS No. 5, discloses matters when losses are probable but not estimable, and expenses legal costs related to the defense of loss contingencies as incurred.

8.

Fair Value of Financial Instruments (All Companies)

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

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

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

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

	At December 31, 2008					
	CL&P		PSNH		WMECO	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	$ 116.2	$ 86.3	$ -	$ -	$ -	$ -
Long-term debt -						
First mortgage bonds	1,669.8	1,737.2	280.0	286.3	-	-
Other long-term debt	604.9	555.8	407.3	359.7	304.4	270.3
Rate reduction bonds	378.2	373.7	235.1	240.7	73.2	75.0

	At December 31, 2007					
	CL&P		PSNH		WMECO	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value	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	170.0	164.6	-	-
Other long-term debt	662.6	674.1	407.3	420.6	304.4	298.1

Rate reduction bonds	548.7	586.2	282.0	297.3	86.7	91.7

The NU consolidated other long-term debt includes $298.6 million and $294.3 million of fees and interest due for spent nuclear fuel disposal costs at December 31, 2008 and 2007, respectively. CL&P's portion of this obligation is $243 million and $238.7 million for the years ended December 31, 2008 and 2007. WMECO's portion of this obligation is $55.6 million at both December 31, 2008 and 2007.

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

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

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

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

9.

Marketable Securities (NU, WMECO)

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

At December 31,

(Millions of Dollars)	**2008**	**2007**
Supplemental benefit trust	$ 53.5	$ 68.4
WMECO spent nuclear fuel trust	55.7	55.7
Totals	$ 109.2	$ 124.1

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

	At December 31, 2008		
(Millions of Dollars)	**Amortized Cost [1]**	**Pre-Tax Gross Unrealized Gains**	**Estimated Fair Value**
Supplemental benefit trust			
United States equity securities	$ 21.9	$ 1.1	$ 23.0
Non-United States equity securities	5.6	-	5.6
U.S. government issued debt securities (Agency and Treasury)	13.1	0.8	13.9
Corporate debt securities	3.3	0.2	3.5
Asset backed securities	3.4	-	3.4
Other	4.1	-	4.1
Total supplemental benefit trust	$ 51.4	$ 2.1	$ 53.5

	At December 31, 2008		
(Millions of Dollars)	**Amortized Cost [1]**	**Pre-Tax Gross Unrealized Gains**	**Estimated Fair Value**
WMECO spent nuclear fuel trust			
Short-term investments and money markets	$ 16.3	$ -	$ 16.3
U.S. government issued debt securities (Agency and Treasury)	15.4	0.1	15.5
Corporate debt securities	17.4	0.5	17.9
Asset backed securities	2.4	-	2.4
Other	3.6	-	3.6
Total WMECO Spent Nuclear Fuel Trust	$ 55.1	$ 0.6	$ 55.7
Total NU Consolidated	$ 106.5	$ 2.7	$ 109.2

	At December 31, 2007		
	Amortized	**Pre-Tax**	**Estimated**

(Millions of Dollars)		**Cost [1]**		**Gross Unrealized Gains**		**Fair Value**
Supplemental benefit trust						
United States equity securities	$	23.5	$	4.3	$	27.8
Non-United States equity securities		8.3		-		8.3
U.S. government issued debt securities (Agency and Treasury)		14.2		0.3		14.5
Corporate debt securities		6.4		0.1		6.5
Asset backed securities		6.3		-		6.3
Other		5.0		-		5.0
Total supplemental benefit trust	$	63.7	$	4.7	$	68.4

WMECO spent nuclear fuel trust						
Short-term investments and money markets	$	14.1	$	-	$	14.1
U.S. government issued debt securities (Agency and Treasury)		0.7		-		0.7
Corporate debt securities		29.2		-		29.2
Asset backed securities		9.2		0.1		9.3
Other		2.4		-		2.4
Total WMECO Spent Nuclear Fuel Trust	$	55.6	$	0.1	$	55.7
Total NU Consolidated	$	119.3	$	4.8	$	124.1

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

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

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

For the years ended December 31, 2008, 2007 and 2006, realized gains and losses recognized on the sale of available-for-sale securities are as follows:

	NU Consolidated			**WMECO**		
(Millions of Dollars)	**Realized Gains**	**Realized Losses**	**Net Realized Gains/(Losses)**	**Realized Gains**	**Realized Losses**	**Net Realized Gains/(Losses)**
2008	$ 2.5	$ (2.2)	$ 0.3	$ 0.2	$ (0.6)	$ (0.4)
2007	2.8	(1.0)	1.8	0.1	(0.1)	-
2006	5.2	(1.3)	3.9	-	(0.3)	(0.3)

The WMECO spent nuclear fuel trust net realized losses above offset the spent nuclear fuel obligation in long-term debt. For the years ended December 31, 2008, 2007 and 2006, all other net realized gains totaling $0.7 million, $1.9 million and $4.2 million, respectively, are included in other income, net on the accompanying consolidated statements of income. Included in the realized gain/(losses) is a pre-tax gain of $3.1 million for the year ended December 31, 2006 related to NU's investment in Globix Corporation (Globix), which was sold on April 6, 2006.

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

Proceeds from the sale of these securities, including proceeds from short-term investments, totaled $259.4 million, $254.8 million and $193.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. WMECO's portion of these proceeds totaled $169.1 million, $196.9 million and $123.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

	NU Consolidated		WMECO	
(Millions of Dollars)	**Amortized Cost**	**Estimated Fair Value**	**Amortized Cost**	**Estimated Fair Value**
Less than one year	$ 49.2	$ 49.9	$ 45.9	$ 46.4
One to five years	11.9	12.0	8.0	8.1
Six to ten years	4.3	4.5	-	-
Greater than ten years	13.6	14.2	1.2	1.2
Subtotal	79.0	80.6	55.1	55.7
Equity securities	27.5	28.6	-	-
Total	$ 106.5	$ 109.2	$ 55.1	$ 55.7

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

10.

Leases (All Companies)

Various NU subsidiaries, including CL&P, PSNH and WMECO, have 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, PSNH and WMECO incur costs associated with leases entered into by NUSCO and RRR. These costs are included below in CL&P, PSNH and WMECO s operating lease payments charged to expense and amounts capitalized as well as future operating lease payments from 2009 through 2013 and thereafter. These amounts are eliminated for NU consolidated. 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 ($2.1 million for CL&P and $0.4 million for PSNH) in 2008, $2.9 million ($2.5 million for CL&P and $0.4 million for PSNH) in 2007, and $3.3 million ($2.9 million for CL&P and $0.4 million for PSNH) in 2006. Interest included in capital lease rental payments was $1.8 million in 2008 ($1.7 million for CL&P and $0.1 million for PSNH), $2 million ($1.8 million for CL&P and $0.2 million for PSNH) in 2007, and $1.9 million ($1.7 million for CL&P and $0.2 million for PSNH) in 2006. Capital lease asset amortization was $0.7 million ($0.4 million for CL&P and $0.3 million for PSNH) in 2008, $0.9 million ($0.7 million for CL&P and $0.2 million for PSNH) in both 2007 and 2006. There was a de minimis amount of capital leases held by WMECO in 2008. There were no capital leases held by WMECO in 2007 or 2006.

Operating lease rental payments charged to expense were $19.1 million, $19.6 million and $10.9 million ($12.7 million, $13.2 million and $17.3 million for CL&P, $4.1 million, $3.5 million and $4.1 million for PSNH and $3.8 million, $4 million and $4 million for WMECO) in 2008, 2007 and 2006, respectively. In 2006, the NU consolidated amount includes $0.7 million included in income from discontinued operations on the accompanying consolidated statements of income for the year ended December 31, 2006. The capitalized portion of operating lease payments was approximately $10.8 million, $10.5 million and $10 million ($6.8 million, $6.5 million and $6.2 million for CL&P, $1.8 million, $2 million and $1.9 million for PSNH and $1.3 million, $1.2 million and $1.1 million for WMECO) for the years ended December 31, 2008, 2007 and 2006, respectively.

Future minimum rental payments excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, at December 31, 2008 are as follows:

Capital Leases		**NU Consolidated**
(Millions of Dollars)		
2009	$	2.4
2010		2.4
2011		2.5
2012		2.6
2013		2.4
Thereafter		15.5
Future minimum lease payments	$	27.8
Less amount representing interest		14.4
Present value of future minimum lease payments	$	13.4

Capital Leases		**CL&P**		**PSNH**
(Millions of Dollars)				
2009	$	1.9	$	0.5
2010		1.9		0.5
2011		1.9		0.5
2012		2.0		0.5
2013		1.9		0.4
Thereafter		14.9		0.5
Future minimum lease payments	$	24.5	$	2.9
Less amount representing interest		13.3		1.0
Present value of future minimum lease payments	$	11.2	$	1.9

Operating Leases		**NU Consolidated**
(Millions of Dollars)		
2009	$	24.6
2010		18.9
2011		7.1
2012		6.1

2013		5.9
Thereafter		23.9
Future minimum lease payments	$	86.5

Operating Leases		**CL&P**		**PSNH**		**WMECO**
(Millions of Dollars)						
2009	$	14.4	$	4.4	$	4.4
2010		12.5		1.3		4.1
2011		3.9		1.1		2.4
2012		3.4		0.9		2.3
2013		3.3		0.9		2.3
Thereafter		19.7		4.1		1.9
Future minimum lease payments	$	57.2	$	12.7	$	17.4

In November 2008, the lessor of CL&P, PSNH, WMECO and Yankee Gas vehicle/equipment master lease agreements notified the companies that it was electing to terminate the lease agreements as permitted under the termination clause of the agreements. The remaining payments under the agreements will be made through November 2009 for PSNH and January 2011 for CL&P, WMECO, and Yankee Gas. See Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," for obligations relating to the termination.

NU (CL&P) entered into certain contracts for the purchase of energy that qualify as leases under EITF No. 01-8, "Determining Whether an Arrangement Contains a Lease." These contracts do not have minimum lease payments and therefore are not included in the tables above. See Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," for further information regarding these contracts.

11.

Long-Term Debt (All Companies)

Long-term debt maturities and cash sinking fund requirements on debt outstanding at December 31, 2008, for the years 2009 through 2013 and thereafter, which include fees and interest due for spent nuclear fuel disposal costs, net unamortized premiums or discounts and other fair value adjustments at December 31, 2008, are as follows (millions of dollars):

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

Details of long-term debt outstanding for CL&P, PSNH and WMECO are as follows (millions of dollars):

CL&P	**At December 31,**	
	2008	**2007**
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% 2004 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	150.0

5.750% 2007 Series B due 2037		150.0		150.0
5.750% 2007 Series C due 2017		100.0		100.0
6.375% 2007 Series D due 2037		100.0		100.0
5.650% 2008 Series A due 2018		300.0		-
Total First Mortgage Bonds		1,669.8		1,369.8
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
Total Pollution Control Notes		361.9		423.9
Total First Mortgage Bonds and Pollution Control Notes		2,031.7		1,793.7
Fees and interest due for spent nuclear fuel disposal costs		243.0		238.7
Less amounts due within one year		-		-
Unamortized premiums and discounts, net		(4.3)		(3.9)
Long-term debt	$	2,270.4	$	2,028.5

PSNH	**At December 31,**			
	2008		**2007**	
First Mortgage Bonds:				
5.25% 2004 Series L, due 2014	$	50.0	$	50.0
5.60% 2005 Series M, due 2035		50.0		50.0
6.15% 2007 Series N, due 2017		70.0		70.0
6.00% 2008 Series O, due 2018		110.0		-
Total First Mortgage Bonds		280.0		170.0
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		(0.5)		(0.3)
Long-term debt	$	686.8	$	577.0

WMECO		**At December 31,**		
		2008		**2007**
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		40.0
Total Pollution Control Notes and Other		248.8		248.8
Fees and interest due for spent nuclear fuel disposal costs		55.6		55.6
Total pollution control notes and fees and interest for spent nuclear fuel disposal costs		304.4		304.4
Less amounts due within one year		-		-
Unamortized premiums and discounts, net		(0.5)		(0.5)
Long-term debt	$	303.9	$	303.9

There are no cash sinking fund requirements or debt maturities for the years 2009 through 2013 for CL&P and PSNH. There are $55 million and $250 million of maturities in 2013 related to the WMECO $55 million Senior Series A Notes and the NU parent $250 million Senior Series C Notes, respectively. CL&P, PSNH and WMECO have $2 billion, $687.3 million and $193.8 million, respectively, of long-term debt maturities in the period thereafter.

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

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

The NU parent, CL&P, PSNH and WMECO tax-exempt bonds contain call provisions ranging between 100 percent and 102 percent of par. All other securities are subject to make-whole provisions.

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

At December 31, 2008 PSNH had $407.3 million in outstanding PCRBs. PSNH s obligation to repay each series of PCRBs is secured by first mortgage bonds and three series, the 2001 Series A, B and C, also carry bond insurance. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. For financial reporting purposes, these first mortgage bonds would not be considered outstanding unless PSNH failed to meet its obligations under the PCRBs. The 2001 Series B PCRBs, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this series of PCRBs has been held by remarketing agents as a result of failed auctions due to general market concerns. The interest rate on these PCRBs has been reset by formula under the applicable documents every 35 days and has been between 0.4 percent and 4 percent since March 2008. The formula is based on a combination of the ratings on the PCRBs and an index rate, which provides for an interest rate of 0.4 percent as of December 31, 2008. The company is not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agents.

NU and its subsidiaries' long-term debt agreements provide that certain of its subsidiaries must comply with certain financial and non-financial covenants as are customarily included in such agreements, including a consolidated debt to capitalization ratio. These subsidiaries are in compliance with these covenants at December 31, 2008.

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

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

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

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

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

The change in fair value totaling a positive $20.8 million and $4.2 million at December 31, 2008 and 2007, respectively, on the accompanying consolidated statements of capitalization reflects the NU parent 7.25 percent amortizing note, due 2012 in the amount of $263 million that is hedged with a fixed to floating interest rate swap. The change in fair value of the interest component of the debt was recorded as an adjustment to long-term debt with an equal and offsetting adjustment to derivative assets and liabilities for the change in fair value of the fixed to floating interest rate swap.

12.

CL&P Preferred Stock Not Subject to Mandatory Redemption (CL&P)

CL&P's charter authorizes it to issue up to 9 million shares of preferred stock ($50 par value per share) of which 2,234,000 shares were outstanding at December 31, 2008 and 2007. 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, 2008 and 2007. 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, 2008 Redemption Price	Shares Outstanding at December 31, 2008 and 2007	December 31, 2008	2007

$1.90	$52.50	163,912	$ 8.2	$ 8.2
Series of 1947				
$2.00	54.00	336,088	16.8	16.8
Series of 1947				
$2.04	52.00	100,000	5.0	5.0
Series of 1949				
$2.20	52.50	200,000	10.0	10.0
Series of 1949				
3.90%	50.50	160,000	8.0	8.0
Series of 1949				
$2.06	51.00	200,000	10.0	10.0
Series E of 1954				
$2.09	51.00	100,000	5.0	5.0
Series F of 1955				
4.50%	50.75	104,000	5.2	5.2
Series of 1956				
4.96%	50.50	100,000	5.0	5.0
Series of 1958				
4.50%	50.50	160,000	8.0	8.0
Series of 1963				
5.28%	51.43	200,000	10.0	10.0
Series of 1967				
$3.24	51.84	300,000	15.0	15.0
Series G of 1968				
6.56%	51.44	200,000	10.0	10.0
Series of 1968				
Totals		2,324,000	$ 116.2	$ 116.2

Dividends of $5.6 million were paid to the preferred stockholders in both 2008 and 2007.

13.

Dividend Restrictions (NU, CL&P, PSNH, WMECO, Yankee Gas)

NU parent's ability to pay dividends is not regulated under the Federal Power Act, but may be affected by certain state statutes, the leverage restriction tied to its consolidated total debt to total capitalization ratio requirement in its revolving credit agreement, and the ability of NU s subsidiaries to pay common dividends to it.

CL&P, PSNH, and WMECO are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in its capital account." Management believes that this Federal Power Act restriction, as applied to CL&P, PSNH and WMECO, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from retained earnings. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas. Such state law restrictions do not restrict payment of dividends from retained earnings or net income. CL&P, PSNH, WMECO and Yankee Gas also have a revolving credit agreement that imposes leverage restrictions including consolidated total debt to total capitalization ratio requirements. The retained earnings balances subject to these leverage restrictions are $1.079 billion for NU consolidated, $617.3 million for CL&P, $283.2 million for PSNH and $82.5 million for WMECO. PSNH is further required to reserve an additional amount under its FERC hydroelectric license conditions. Approximately $11 million of PSNH's retained earnings is subject to restriction under its FERC hydroelectric license conditions. At December 31, 2008, NU, CL&P, PSNH, WMECO and Yankee Gas were in compliance with all such provisions of its credit agreement that may restrict the payment of dividends.

14.

Accumulated Other Comprehensive Income/(Loss) (NU, CL&P, PSNH, WMECO, NU Enterprises, Yankee Gas)

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

NU Consolidated *(Millions of Dollars)*	**December 31, 2006**	**2007 Change**	**December 31, 2007**	**2008 Change**	**December 31, 2008**
Qualified cash flow hedging instruments	$ 5.9	$ (3.6)	$ 2.3	$ (6.9)	$ (4.6)
Unrealized gains on securities	3.0	(0.1)	2.9	(1.7)	1.2
Pension, SERP and other postretirement plans benefit obligations (SFAS No. 158)	(4.4)	8.6	4.2	(38.1)	(33.9)
Accumulated other comprehensive income/(loss)	$ 4.5	$ 4.9	$ 9.4	$ (46.7)	$ (37.3)

CL&P *(Millions of Dollars)*	**December 31, 2006**	**2007 Change**	**December 31, 2007**	**2008 Change**	**December 31, 2008**
Qualified cash flow hedging instruments	$ 4.5	$ (4.8)	$ (0.3)	$ (3.3)	$ (3.6)
Unrealized gains on securities	0.1	-	0.1	(0.1)	-
Accumulated other comprehensive income/(loss)	$ 4.6	$ (4.8)	$ (0.2)	$ (3.4)	$ (3.6)

The unrealized gains on securities above relate to $1.8 million and $2.4 million of securities held in the supplemental benefit trust at December 31, 2008 and 2007, respectively. The fair value of these securities is included in prepayments and other on the accompanying consolidated balance sheets.

PSNH *(Millions of Dollars)*	**December 31, 2006**	**2007 Change**	**December 31, 2007**	**2008 Change**	**December 31, 2008**

Qualified cash flow hedging instruments	$	-	$	0.6	$	0.6	$	(1.4)	$	(0.8)
Unrealized gains on securities		0.2		-		0.2		(0.1)		0.1
Accumulated other comprehensive income/(loss)	$	0.2	$	0.6	$	0.8	$	(1.5)	$	(0.7)

The unrealized gains on securities above relate to $3.2 million and $4 million of securities held in the supplemental benefit trust at December 31, 2008 and 2007, respectively. The fair value of these securities is included in prepayments and other on the accompanying consolidated balance sheets.

WMECO *(Millions of Dollars)*		**December 31, 2006**		**2007 Change**		**December 31, 2007**		**2008 Change**		**December 31, 2008**
Qualified cash flow hedging instruments	$	0.9	$	(0.7)	$	0.2	$	(0.1)	$	0.1
Unrealized gains on securities		-		-		-		0.1		0.1
Accumulated other comprehensive income/(loss)	$	0.9	$	(0.7)	$	0.2	$	-	$	0.2

The unrealized gains on securities above relate to the investments in the WMECO spent nuclear fuel trust included in marketable securities and $0.5 million and $0.7 million as of December 31, 2008 and 2007, respectively, of securities held in the supplemental benefit trust, which are included in prepayments and other and marketable securities, respectively, on the accompanying consolidated balance sheets.

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

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

CL&P

(Millions of Dollars)	2008	2007	2006
Qualified cash flow hedging instruments	$ 2.2	$ 3.2	$ (3.1)
Minimum SERP liability	-	-	(0.2)
Accumulated other comprehensive income/(loss)	$ 2.2	$ 3.2	$ (3.3)

PSNH

(Millions of Dollars)	2008	2007	2006
Qualified cash flow hedging instruments	$ 1.0	$ 0.4	$ -
Accumulated other comprehensive income	$ 1.0	$ 0.4	$ -

WMECO

(Millions of Dollars)	2008	2007	2006
Qualified cash flow hedging instruments	$ 0.1	$ (0.5)	$ (0.1)
Unrealized losses on securities	-	-	0.2
Accumulated other comprehensive income/(loss)	$ 0.1	$ (0.5)	$ 0.1

Fair value adjustments included in accumulated other comprehensive income/(loss) for NU consolidated, CL&P, PSNH, and WMECO qualified cash flow hedging instruments are as follows:

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

	At December 31,					
		2008			2007	
(Millions of Dollars, Net of Tax)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Balance at beginning of year	$ (0.3)	$ 0.6	$ 0.2	$ 4.5	$ -	$ 0.9
Hedged transactions recognized into earnings	0.4	0.2	(0.1)	0.1	-	(0.1)
Change in fair value of interest rate swap agreements	(3.7)	(1.4)	-	-	-	-
Cash flow transactions entered into for period	-	(0.2)	-	(4.9)	0.6	(0.6)
Net change associated with hedging transactions	(3.3)	(1.4)	(0.1)	(4.8)	0.6	(0.7)
Total fair value adjustments included in accumulated other	$ (3.6)	$ (0.8)	$ 0.1	$ (0.3)	$ 0.6	$ 0.2

comprehensive income

Hedged transactions recognized into earnings in the tables above represent amounts that were reclassified from accumulated other comprehensive income into earnings in connection with the consummation of interest rate swap agreements and the amortization of existing interest rate hedges. These amounts are net of income taxes of approximately $0.2 million, $0.2 million, $0.1 million and $(0.1) million for NU consolidated, CL&P, PSNH and WMECO, respectively, for the year ended December 31, 2008.

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

	2008				2007		
	NU parent	**CL&P**	**PSNH**	**Yankee Gas**	**CL&P**	**CL&P**	**WMECO**
Long-term debt issued (in millions)	$250	$300	$110	$100	$150 and $150	$100 and $100	$40
Date entered into swap transaction	12/3/07	12/5/07	12/4/07	12/4/07	2/22/07	7/16/07	7/17/07
Term	5-year	10-year	10-year	10-year	10-year and 30-year	10-year and 30-year	30-year
Termination date	6/2/08	5/19/08	3/24/08 (3)	9/23/08 (4)	3/27/07	09/10/07	8/15/07
Loaded LIBOR swap percentage rate(s) (percentage)	4.102 (1)	4.590 and 4.602 (2)	4.5575 and 4.147 (3)	4.635 and 4.5685 (4)	5.229 and 5.369 (7)	5.718 and 5.865 (9)	5.882
Charge to accumulated other comprehensive income (net of tax) (5)	$0.1	$2.3	$0.9 (6)	$0.7	$1.6	$4.7 (8)	$0.6

(1)

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

(2)

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

(3)

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

(4)

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

(5)

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

(6)

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

(7)

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

(8)

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

(9)

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

For NU consolidated, it is estimated that a charge of $0.2 million will be reclassified from accumulated other comprehensive income as a decrease to earnings over the next 12 months as a result of amortization of the interest rate swap agreements, which have been settled. Included in this amount are estimated charges of $0.4 million and $0.1 million for CL&P and PSNH, respectively, and a benefit of $0.1 million for WMECO. At December 31, 2008, it is estimated that a pre-tax amount of $0.7 million included in the accumulated other comprehensive income balance will be reclassified as a decrease to earnings over the next 12 months related to Pension, SERP and other postretirement benefits adjustments for NU consolidated.

15.

Restructuring and Impairment Charges and Discontinued Operations (NU, NU Enterprises)

Restructuring and Impairment Charges: NU Enterprises recorded $0.2 million and $27.6 million of pre-tax restructuring and impairment charges for the years ended December 31, 2007 and 2006, respectively, relating to the decision to exit NU Enterprises. There were no restructuring and impairment charges recorded in 2008. These charges are included as part of the NU Enterprises reportable segment in Note 17, "Segment Information," to the consolidated financial statements.

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

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

(Millions of Dollars)	**Employee-Related Costs**	**Professional and Other Fees**	**Total**
Restructuring liability as of January 1, 2005	$ -	$ -	$ -
Costs incurred	2.3	7.4	9.7
Cash payments and other deductions/reversals	(0.5)	(3.2)	(3.7)
Restructuring liability as of December 31, 2005	1.8	4.2	6.0
Costs incurred	3.3	24.0	27.3
Cash payments and other deductions/reversals	(3.7)	(25.9)	(29.6)
Restructuring liability as of December 31, 2006	1.4	2.3	3.7
Costs incurred	-	0.2	0.2
Cash payments and other deductions/reversals	(1.4)	(2.2)	(3.6)
Restructuring liability as of December 31, 2007 and 2008	$ -	$ 0.3	$ 0.3

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

Summarized financial information for the discontinued operations is as follows:

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

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

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

No intercompany revenues were included in discontinued operations for the years ended December 31, 2008 or 2007. For the year ended December 31, 2006, included in discontinued operations are $161 million of intercompany revenues that are not eliminated in consolidation due to the separate presentation of discontinued operations. Of this amount, $160.7 million represents revenues on intercompany contracts between the generation operations of NGC and Mt. Tom and Select Energy. NGC's and Mt. Tom's revenues and earnings related to these contracts are included in discontinued operations while Select Energy's related expenses and losses are included in continuing operations. Select Energy's obligation to NGC and Mt. Tom ended at the time of sale in 2006.

At December 31, 2008, NU did not have or expect to have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations.

16.

Earnings Per Share (NU)

EPS is computed based upon the weighted average number of common shares outstanding, excluding unallocated ESOP shares, during each year. Diluted EPS is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common stock. In 2006, 2,500 options were excluded from the following table as these options were antidilutive. In 2008 and 2007, there were no antidilutive options outstanding.

The following table sets forth the components of basic and diluted EPS:

(Millions of Dollars, except share information)		**2008**		**2007**		**2006**
Income from continuing operations	$	260.8	$	245.9	$	132.9
Income from discontinued operations		-		0.6		337.7
Net income	$	260.8	$	246.5	$	470.6
Basic common shares outstanding (average)		155,531,846		154,759,727		153,767,527

Dilutive effect		467,394		544,634		379,142
Fully diluted common shares outstanding (average)		155,999,240		155,304,361		154,146,669
Basic EPS:						
Income from continuing operations	$	1.68	$	1.59	$	0.86
Income from discontinued operations		-		-		2.20
Net income	$	1.68	$	1.59	$	3.06
Fully Diluted EPS:						
Income from continuing operations	$	1.67	$	1.59	$	0.86
Income from discontinued operations		-		-		2.19
Net income	$	1.67	$	1.59	$	3.05

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

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

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

17.

Segment Information (All Companies)

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

The regulated companies segments, including the electric distribution and transmission segments, as well as the gas distribution segment (Yankee Gas), represented approximately 99 percent, 99 percent and 87 percent of NU's total consolidated revenues for the years ended December 31, 2008, 2007 and 2006, respectively.

The NU Enterprises segment is comprised of the following: 1) Select Energy (wholesale contracts), 2) Boulos, 3) NGS, 4) NGS Mechanical, 5) SECI, and 6) NU Enterprises parent.

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

Effective on January 1, 2007, financial information for the remaining operations of HWP that were not exited as part of the sale of the competitive generation business was included as part of the Other reportable segment as these operations were no longer considered part of NU Enterprises subsequent to the sale. Accordingly, HWP s remaining operations have been presented as part of the Other reportable segment for the year ended December 31, 2007. Effective December 31, 2008, HWP and HP&E transferred $4 million in transmission related assets to WMECO and are included in WMECO's transmission segment.

As a result of the sale of NU Enterprises' retail marketing and competitive generation businesses, the financial information used by management was reduced to the remaining wholesale contracts, the operations of the remaining energy services businesses and NU Enterprises parent. As a result of exiting these businesses in 2006, the operations of NU Enterprises have been aggregated and presented as one reportable segment for the years ended December 31, 2008, 2007 and 2006.

NU's consolidated statements of income for the years ended December 31, 2007 and 2006 present the operations for NGC, including certain components of NGS, Mt. Tom, SESI, a portion of the former Woods Electrical and SECI as discontinued operations. For further information and information regarding the exit from these businesses, see Note 15, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements.

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

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

Customer Concentrations: Select Energy provided basic generation service in the New Jersey market through 2007. In 2006 and 2005, Select Energy also provided service in the Maryland market. Select Energy billings related to these contracts represented $116.1 million and $404.4 million for the years ended December 31, 2007 and 2006, respectively, of total NU Enterprises' billings. No other individual customer represented in excess of 10 percent of NU Enterprises' billings for the years ended December 31, 2008, 2007 and 2006. As these contracts expire, billings under a long-term contract with NYMPA will likely exceed 10 percent of NU Enterprises' billings in future periods.

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

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

NU s segment information for the years ended December 31, 2008, 2007 and 2006 is as follows (some amounts may not agree between the financial statements and the segment schedules due to rounding):

	For the Year Ended December 31, 2008						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	**Electric**	**Gas**	**Transmission**	**NU Enterprises**	**Other**	**Eliminations**	**Total**
Operating revenues	$ 4,716.1	$ 577.4	$ 424.8	$ 114.1	$ 416.6	$ (448.9)	$ 5,800.1
Depreciation and amortization	(581.5)	(26.2)	(49.3)	(0.6)	(13.1)	0.9	(669.8)
Other operating expenses	(3,828.6)	(487.3)	(138.5)	(89.6)	(431.2)	435.7	(4,539.5)
Operating income/(loss)	306.0	63.9	237.0	23.9	(27.7)	(12.3)	590.8
Interest expense, net of AFUDC	(164.3)	(21.6)	(51.8)	(5.6)	(35.4)	9.6	(269.1)
Interest income	14.1	0.5	2.1	1.0	8.5	(10.6)	15.6

Other income, net	13.1	0.3	21.8	-	227.5	(227.9)	34.8
Income tax (expense)/benefit	(41.6)	(16.0)	(68.8)	(6.2)	28.7	(1.8)	(105.7)
Preferred dividends	(3.6)	-	(2.0)	-	-	-	(5.6)
Net income	$ 123.7	$ 27.1	$ 138.3	$ 13.1	$ 201.6	$ (243.0)	$ 260.8
Total assets (2)	$ 11,968.0	$ 1,424.8	$ -	$ 85.2	$ 5,060.1	$ (4,549.6)	$ 13,988.5
Cash flows for total investments in plant (3)	$ 487.8	$ 58.4	$ 678.9	$ -	$ 30.3	$ -	$ 1,255.4

	For the Year Ended December 31, 2007						
	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
Depreciation and amortization	(428.5)	(24.7)	(37.4)	(0.5)	(16.7)	0.8	(507.0)
Other operating expenses	(4,192.5)	(437.1)	(115.5)	(77.9)	(358.3)	405.6	(4,775.7)
Operating income	309.8	52.3	145.8	19.3	14.8	(2.5)	539.5
Interest expense, net of AFUDC	(167.9)	(19.0)	(36.7)	(8.9)	(33.3)	25.6	(240.2)
Interest income	6.0	-	3.8	2.4	34.3	(26.6)	19.9
Other income, net	27.6	1.2	13.0	-	158.3	(158.4)	41.7
Income tax expense	(47.9)	(11.9)	(41.8)	(1.7)	(3.0)	(3.1)	(109.4)
Preferred dividends	(4.0)	-	(1.6)	-	-	-	(5.6)
Income from continuing operations	123.6	22.6	82.5	11.1	171.1	(165.0)	245.9
Income from discontinued operations	-	-	-	0.6	-	-	0.6
Net income	$ 123.6	$ 22.6	$ 82.5	$ 11.7	$ 171.1	$ (165.0)	$ 246.5
Total assets (2)	$ 9,977.1	$ 1,309.1	$ -	$ 150.6	$ 4,154.3	$ (4,009.3)	$ 11,581.8
Cash flows for total investments in plant (3)	$ 372.3	$ 57.6	$ 668.9	$ 0.9	$ 15.1	$ -	$ 1,114.8

For the Year Ended December 31, 2006

Regulated Companies

(Millions of Dollars)	**Distribution (1)** **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
Depreciation and amortization	(387.2)	(22.7)	(29.8)	(0.7)	(18.8)	14.1	(445.1)
Other operating expenses	(4,652.5)	(401.0)	(93.6)	(1,076.8)	(335.9)	363.2	(6,196.6)
Operating income/(loss)	296.3	30.2	92.6	(175.7)	0.3	(7.7)	236.0
Interest expense, net of AFUDC	(160.1)	(16.5)	(22.4)	(26.9)	(37.1)	24.8	(238.2)
Interest income	8.4	-	0.4	5.1	32.8	(28.3)	18.4
Other income, net	31.9	1.4	6.8	0.1	205.2	(199.5)	45.9
Income tax benefit/(expense)	13.4	(3.2)	(16.4)	78.1	5.0	(0.6)	76.3
Preferred dividends	(4.3)	-	(1.2)	-	-	-	(5.5)
Income/(loss) from continuing operations	185.6	11.9	59.8	(119.3)	206.2	(211.3)	132.9
Income from discontinued operations	-	-	-	330.6	-	7.1	337.7
Net income	$ 185.6	$ 11.9	$ 59.8	$ 211.3	$ 206.2	$ (204.2)	$ 470.6
Cash flows for total investments in plant (3)	$ 305.8	$ 87.6	$ 430.9	$ 25.8	$ 22.1	$ -	$ 872.2

(1)

Includes PSNH generation activities.

(2)

Information for segmenting total assets between electric distribution and transmission is not available at December 31, 2008 and 2007. On a NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution columns above.

(3)

Cash flows for total investments in plant included in the segment information above are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income.

The segment information related to the distribution and transmission businesses for CL&P for the years ended December 31, 2008, 2007 and 2006 is as follows:

	CL&P - For the Year Ended December 31, 2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues (2)	$ 3,218.5	$ 339.9	$ 3,558.4
Depreciation and amortization	(433.1)	(39.4)	(472.5)
Other operating expenses	(2,610.5)	(102.0)	(2,712.5)
Operating income	174.9	198.5	373.4
Interest expense, net of AFUDC	(102.1)	(44.1)	(146.2)
Interest income	9.2	1.6	10.8
Other income, net	12.4	18.7	31.1
Income tax expense	(20.8)	(57.1)	(77.9)
Net income	$ 73.6	$ 117.6	$ 191.2
Cash flows for total investments in plant (3)	$ 294.3	$ 555.2	$ 849.5

	CL&P - For the Year Ended December 31, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues (2)	$ 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
Cash flows for total investments in plant (3)	$ 242.3	$ 583.9	$ 826.2

	CL&P - For the Year Ended December 31, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues (2)	$ 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
Cash flows for total investments in plant (3)	$	183.8	$	383.4	$	567.2

The segment information related to the distribution (including generation) and transmission businesses for PSNH for the years ended December 31, 2008, 2007 and 2006 is as follows:

	PSNH - For the Year Ended December 31, 2008					
(Millions of Dollars)	**Distribution (1)**		**Transmission**		**Totals**	
Operating revenues (2)	$	1,082.2	$	59.0	$	1,141.2
Depreciation and amortization		(104.0)		(7.2)		(111.2)
Other operating expenses		(882.8)		(24.3)		(907.1)
Operating income		95.4		27.5		122.9
Interest expense, net of AFUDC		(44.6)		(5.6)		(50.2)
Interest income		2.9		0.5		3.4
Other income, net		1.4		2.6		4.0
Income tax expense		(13.7)		(8.3)		(22.0)
Net income	$	41.4	$	16.7	$	58.1
Cash flows for total investments in plant (3)	$	158.6	$	80.3	$	238.9

	PSNH - 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
Cash flows for total investments in plant (3)	$ 100.1	$ 67.6	$ 167.7

	PSNH - 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
Cash flows for total investments in plant (3)	$ 92.3	$ 34.4	$ 126.7

The segment information related to the distribution and transmission businesses for WMECO for the years ended December 31, 2008, 2007 and 2006 is as follows:

	WMECO - For the Year Ended December 31, 2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues (2)	$ 415.6	$ 25.9	$ 441.5

Depreciation and amortization		(44.4)		(2.7)		(47.1)
Other operating expenses		(335.5)		(12.4)		(347.9)
Operating income		35.7		10.8		46.5
Interest expense, net of AFUDC		(17.5)		(2.1)		(19.6)
Interest income		1.9		0.1		2.0
Other income, net		(0.7)		0.6		(0.1)
Income tax benefit		(7.1)		(3.4)		(10.5)
Net income	$	12.3	$	6.0	$	18.3
Cash flows for total investments in plant (3)	$	34.9	$	43.4	$	78.3

	WMECO - For the Year Ended December 31, 2007					
(Millions of Dollars)	Distribution		Transmission		Totals	
Operating revenues (2)	$	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
Cash flows for total investments in plant (3)	$	29.9	$	17.4	$	47.3

	WMECO - For the Year Ended December 31, 2006					
	Distribution		Transmission		Totals	
Operating revenues (2)	$	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
Cash flows for total investments in plant (3)	$	29.7	$	13.1	$	42.8

(1)

Includes PSNH generation activities.

(2)

CL&P, PSNH and WMECO revenues are primarily derived from residential, commercial and industrial customers and are not dependent on any single customer.

(3)

Cash flows for total investments in plant included in the segment information above are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income.

18.

Subsequent Event (NU, CL&P)

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

NU Consolidated Statements of Quarterly Financial Data (Unaudited)

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

2007				
Operating Revenues	$ 1,703,518	$ 1,391,772	$ 1,450,977	$ 1,275,959
Operating Income	155,733	116,808	123,360	143,580
Income from Continuing Operations	76,407	46,012	50,182	73,295
(Loss)/Income from Discontinued Operations	(1,313)	2,541	(58)	(583)
Net Income	75,094	48,553	50,124	72,712
Basic and Fully Diluted Earnings/(Loss) Per Common Share:				
Income from Continuing Operations	$ 0.50	$ 0.30	$ 0.32	$ 0.47
(Loss)/Income from Discontinued Operations	(0.01)	0.01	-	-
Net Income	$ 0.49	$ 0.31	$ 0.32	$ 0.47

(a)

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

CL&P Consolidated Quarterly Financial Data (Unaudited)

(Thousands of Dollars)	Quarter Ended March 31,	June 30,	September 30,	December 31,
2008				
Operating Revenues	$ 885,499	$ 821,875	$ 980,507	$ 870,480
Operating Income	89,814	89,635	98,153	95,789
Net Income	46,068	46,255	55,535	43,300
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

PSNH Consolidated Quarterly Financial Data (Unaudited)

(Thousands of Dollars)	Quarter Ended March 31,	June 30,	September 30,	December 31,
2008				
Operating Revenues	$ 291,765	$ 274,039	$ 301,033	$ 274,365
Operating Income	34,865	30,045	29,364	28,675
Net Income	16,689	13,691	14,318	13,369
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

WMECO Consolidated Quarterly Financial Data (Unaudited)

(Thousands of Dollars)	Quarter Ended March 31,	June 30,	September 30,	December 31,
2008				
Operating Revenues	$ 115,759	$ 104,215	$ 112,280	$ 109,273
Operating Income	15,179	9,643	10,771	10,954
Net Income	6,320	3,249	5,236	3,525

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

NU Selected Consolidated Sales Statistics
(Unaudited)

	2008	2007	2006	2005	2004
Revenues: *(Thousands)*					
Regulated companies:					
Residential	$ 2,525,635	$ 2,558,547	$ 2,409,414	$ 2,080,395	$ 1,707,434
Commercial	1,607,224	1,735,923	1,977,444	1,727,278	1,429,608
Industrial	399,753	412,381	589,742	577,834	513,999
Wholesale	545,127	392,675	388,635	411,361	344,254
Streetlighting and Railroads	38,522	45,880	52,853	47,769	41,976
Miscellaneous and eliminations	24,673	84,043	133,925	159,402	143,431
Total Electric	5,140,934	5,229,449	5,552,013	5,004,039	4,180,702
Total Gas	577,390	514,185	453,894	503,303	407,812
Total - Regulated companies	$ 5,718,324	$ 5,743,634	$ 6,005,907	$ 5,507,342	$ 4,588,514
NU Enterprises:					
Retail	$ -	$ -	$ 583,829	$ 1,212,176	$ 857,355
Wholesale	31,882	25,992	20,163	644,541	1,722,603
Generation	-	-	258,178	210,833	196,191
Services	78,625	68,324	39,887	102,327	117,500
Miscellaneous and eliminations	3,574	3,354	(243)	(257,750)	(245,745)
Total - NU Enterprises	$ 114,081	$ 97,670	$ 901,814	$ 1,912,127	$ 2,647,904
Other miscellaneous and eliminations	(32,310)	(19,078)	(30,034)	(73,243)	(755,734)
Total	$ 5,800,095	$ 5,822,226	$ 6,877,687	$ 7,346,226	$ 6,480,684
Regulated companies - Sales: *(GWH)*					
Residential	14,509	15,051	14,652	15,518	14,866
Commercial	14,885	15,103	14,886	15,234	14,710
Industrial	5,149	5,635	5,750	6,023	6,274
Wholesale	3,576	3,855	8,777	4,856	5,787
Streetlighting and	340	353	332	348	348

Railroads					
Total	38,459	39,997	44,397	41,979	41,985
Regulated companies - Customers: *(Average)*					
Residential	1,700,207	1,697,073	1,686,169	1,674,563	1,659,419
Commercial	190,067	189,727	188,281	195,844	194,233
Industrial	7,342	7,291	7,406	7,638	7,752
Streetlighting and Railroads	4,605	3,855	3,873	3,912	3,930
Total Electric	1,902,221	1,897,946	1,885,729	1,881,957	1,865,334
Gas	204,834	202,743	199,377	196,870	194,212
Total	2,107,055	2,100,689	2,085,106	2,078,827	2,059,546

CL&P Selected Consolidated Sales Statistics (Unaudited)

	2008	2007	2006	2005	2004
Revenues: *(Thousands)*					
Residential	$ 1,811,845	$ 1,854,404	$ 1,709,700	$ 1,440,142	$ 1,155,492
Commercial	1,042,077	1,182,196	1,405,281	1,170,038	939,579
Industrial	190,723	208,087	380,479	327,598	275,730
Wholesale	484,843	347,514	318,958	344,650	295,833
Streetlighting and Railroads	28,710	35,370	42,099	37,054	31,897
Miscellaneous	163	54,246	123,294	146,938	134,393
Total	$ 3,558,361	$ 3,681,817	$ 3,979,811	$ 3,466,420	$ 2,832,924
Sales: *(GWH)*					
Residential	9,913	10,336	10,053	10,760	10,305
Commercial	9,993	10,128	9,995	10,307	9,922
Industrial	2,945	3,264	3,306	3,501	3,623
Wholesale	3,637	3,563	3,749	4,179	5,375
Streetlighting and Railroads	294	304	284	298	298
Total	26,782	27,595	27,387	29,045	29,523
Customers: *(Average)*					
Residential	1,094,991	1,091,799	1,084,937	1,078,723	1,071,249
Commercial	102,464	102,411	101,563	108,558	108,865
Industrial	3,613	3,743	3,848	3,976	4,078
Other	2,883	2,583	2,592	2,630	2,694

Total	1,203,951	1,200,536	1,192,940	1,193,887	1,186,886

PSNH Selected Consolidated Sales Statistics
(Unaudited)

	2008	2007	2006	2005	2004
Revenues: *(Thousands)*					
Residential	$ 472,486	$ 457,616	$ 467,517	$450,230	$ 384,667
Commercial	431,461	413,196	439,828	423,884	361,603
Industrial	169,785	156,258	166,132	190,299	175,921
Wholesale	35,935	25,030	52,255	34,688	19,712
Streetlighting and Railroads	6,515	6,018	5,729	5,685	5,297
Miscellaneous	25,020	24,954	9,439	23,641	21,549
Total	$ 1,141,202	$ 1,083,072	$ 1,140,900	$1,128,427	$ 968,749
Sales: *(GWH)*					
Residential	3,105	3,176	3,087	3,162	3,015
Commercial	3,361	3,403	3,342	3,342	3,235
Industrial	1,435	1,528	1,582	1,612	1,716
Wholesale	(243)	105	985	501	242
Streetlighting and Railroads	25	24	23	24	25
Total	7,683	8,236	9,019	8,641	8,233
Customers: *(Average)*					
Residential	418,107	417,420	413,980	408,959	403,088
Commercial	70,807	70,341	69,528	68,232	66,572
Industrial	2,978	2,770	2,761	2,768	2,783
Other	970	602	592	600	572
Total	492,862	491,133	486,861	480,559	473,015

WMECO Selected Consolidated Sales Statistics
(Unaudited)

	2008	2007	2006	2005	2004
Revenues: *(Thousands)*					
Residential	$ 241,303	$ 246,526	$ 232,197	$190,023	$ 167,275
Commercial	133,686	140,531	132,336	133,356	128,425
Industrial	39,245	48,036	43,131	59,937	62,347

Wholesale	24,349	20,131	17,421	19,064	8,646
Streetlighting and Railroads	3,297	4,492	5,025	5,030	4,782
Miscellaneous	(353)	5,029	1,399	1,983	7,754
Total	$ 441,527	$ 464,745	$ 431,509	$409,393	$ 379,229
Sales: *(GWH)*					
Residential	1,491	1,539	1,511	1,596	1,546
Commercial	1,547	1,589	1,574	1,616	1,583
Industrial	769	842	862	910	935
Wholesale	179	178	189	176	169
Streetlighting and Railroads	22	25	25	25	25
Total	4,008	4,173	4,161	4,323	4,258
Customers: *(Average)*					
Residential	187,109	187,854	187,252	186,882	185,083
Commercial	16,916	17,096	17,310	19,174	18,917
Industrial	751	777	798	894	892
Other	785	703	705	714	695
Total	205,561	206,430	206,065	207,664	205,587

SCHEDULE I

NORTHEAST UTILITIES (PARENT)

FINANCIAL INFORMATION OF REGISTRANT

BALANCE SHEETS

AT DECEMBER 31, 2008 AND 2007

(Thousands of Dollars)

	2008	2007
ASSETS		
Current Assets:		
Cash	$ 1,294	$ 294
Notes receivable from affiliated companies	304,704	115,600
Accounts receivable	2,757	452
Accounts receivable from affiliated companies	1,221	4,690
Taxes receivable	4,932	6,971
Derivative assets - current	-	5,133
Prepayments and other	378	119
	315,286	133,259
Deferred Debits and Other Assets:		
Investments in subsidiary companies, at equity	3,551,308	3,235,694
Accumulated deferred income taxes	25,425	21,058
Derivative assets - long-term	20,827	-
Other	18,676	18,153
	3,616,236	3,274,905
Total Assets	$ 3,931,522	$ 3,408,164
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 303,519	$ 42,000
Long-term debt - current portion	-	150,000

Accounts payable		7		27
Accounts payable to affiliated companies		35,515		1,743
Accrued interest		5,972		5,180
Other		422		425
		345,435		199,375
Deferred Credits and Other Liabilities:				
Other		32,031		27,811
		32,031		27,811
Capitalization:				
Long-Term Debt		533,744		267,143
Common shares, $5 par value - authorized 225,000,000 shares; 176,212,275 shares issued and 155,834,361 shares outstanding in 2008 and 175,924,694 shares issued and 155,079,770 shares outstanding in 2007		881,061		879,623
Capital surplus, paid in		1,475,006		1,465,946
Deferred contribution plan - employee stock ownership plan		(15,481)		(26,352)
Retained earnings		1,078,594		946,792
Accumulated other comprehensive (loss)/income		(37,265)		9,359
Treasury stock, 19,708,136 shares in 2008 and 19,705,545 shares in 2007		(361,603)		(361,533)
Common Shareholders' Equity		3,020,312		2,913,835
Total Capitalization		3,554,056		3,180,978
Total Liabilities and Capitalization	$	3,931,522	$	3,408,164

SCHEDULE I

NORTHEAST UTILITIES (PARENT)

FINANCIAL INFORMATION OF REGISTRANT

STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

(Thousands of Dollars, Except Share Information)

	2008	2007	2006
Operating Revenues	$ -	$ -	$ -
Operating Expenses:			
Other	53,484	3,786	4,063
Operating Loss	(53,484)	(3,786)	(4,063)
Interest Expense	30,893	27,993	32,945
Other Income:			
Equity in earnings of subsidiaries	307,908	247,786	473,279
Other, net	6,956	30,516	29,493
Other Income, Net	314,864	278,302	502,772
Income Before Income Tax (Benefit)/Expense	230,487	246,523	465,764
Income Tax (Benefit)/Expense	(30,341)	40	(4,814)
Net Income	$ 260,828	$ 246,483	$ 470,578
Basic Earnings Per Common Share	$ 1.68	$ 1.59	$ 3.06
Fully Diluted Earnings Per Common Share	$ 1.67	$ 1.59	$ 3.05

Basic Common Shares Outstanding (weighted average)	155,531,846	154,759,727	153,767,527
Fully Diluted Common Shares Outstanding (weighted average)	155,999,240	155,304,361	154,146,669

S-2

SCHEDULE I

NORTHEAST UTILITIES (PARENT)

FINANCIAL INFORMATION OF REGISTRANT

STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

(Thousands of Dollars)

	2008	2007	2006
Operating Activities:			
Net income	$ 260,828	$ 246,483	$ 470,578
Adjustments to reconcile to net cash flows provided by/(used in) operating activities:			
Equity in earnings of subsidiaries	(307,908)	(247,786)	(473,279)
Cash dividends received from subsidiaries	215,162	141,891	190,759
Deferred income taxes	(3,164)	(14,324)	11,582
Stock-based compensation expense	13,518	13,855	14,718
Decrease/(increase) in other deferred debits	108	106	(9,170)
Increase in other deferred credits	340	1,725	1,064
Other adjustments	(1,390)	(849)	(815)
Changes in current assets and liabilities:			
Receivables, including affiliate receivables	883	(906)	4,285
Prepayments and other current assets	(256)	3	14
Accounts payable, including affiliate payables	33,752	1,446	(448)
Taxes receivable/accrued	3,580	(244,675)	228,363
Accrued interest and other current liabilities	2,707	(444)	214
Net cash flows provided by/(used in) operating activities	218,160	(103,475)	437,865
Investing Activities:			
Capital contributions to subsidiaries	(323,164)	(683,427)	(156,577)
Return of investment in subsidiaries	30,000	19,869	435,000
(Increase)/decrease in NU Money Pool	(84,600)	871,800	(595,200)

lending			
(Increase)/decrease in notes receivable from affiliated companies	(79,504)	(42,000)	32,000
Other investing activities	1,557	1,462	2,185
Net cash flows (used in)/provided by investing activities	(455,711)	167,704	(282,592)
Financing Activities:			
Issuance of common shares related to shared-based compensation	5,524	9,056	9,494
Cash dividends on common shares	(129,077)	(120,988)	(112,745)
Increase/(decrease) in short-term debt	261,519	42,000	(32,000)
Issuance of long-term debt	250,000	-	-
Retirements of long-term debt	(150,000)	-	(21,000)
Other financing activities	585	4,206	2,379
Net cash flows provided by/(used in) financing activities	238,551	(65,726)	(153,872)
Net increase/(decrease) in cash	1,000	(1,497)	1,401
Cash - beginning of year	294	1,791	390
Cash - end of year	$ 1,294	$ 294	$ 1,791
Supplemental Cash Flow Information:			
Cash paid/(received) during the year for:			
Interest, net of amounts capitalized	$ 27,522	$ 25,580	$ 32,498
Income taxes	$ (37,063)	$ 259,707	$ (651)

Schedule II

Northeast Utilities and Subsidiaries

Valuation and Qualifying Accounts and Reserves

For the Years Ended December 31, 2008, 2007 and 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 (a)	Deductions - describe (b)	Balance at end of period
NU Consolidated:					
Reserves deducted from assets - reserves for uncollectible accounts:					
2008	$ 25,529	$ 28,573	$ 81,991	$ 92,818	$ 43,275
2007	22,369	29,140	(7,106)	18,874	25,529
2006 (c)	25,044	29,366	1,922	33,963	22,369
CL&P:					
Reserves deducted from assets - reserves for uncollectible accounts:					
2008	$ 7,874	$ 5,951	$ 81,129	$ 70,998	$ 23,956
2007	1,679	18,121	(8,243)	3,683	7,874
2006	1,982	13,582	6,470	20,355	1,679

PSNH:										
Reserves deducted from assets - reserves for uncollectible accounts:										
2008	$	2,675	$	5,661	$	483	$	4,654	$	4,165
2007		2,626		3,433		324		3,708		2,675
2006		2,362		4,208		316		4,260		2,626
WMECO:										
Reserves deducted from assets - reserves for uncollectible accounts:										
2008	$	5,699	$	8,185	$	234	$	7,547	$	6,571
2007		5,073		6,922		155		6,451		5,699
2006		3,653		5,503		194		4,277		5,073

(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 2006, the DPUC issued an order allowing CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2008, CL&P and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $41 million and $10 million, respectively. 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. 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)

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

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. Management contracts and compensation plans or arrangements are designated with a (+).

Exhibit

Number

Description

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 filed 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 27, 2008 (Exhibit 2, PSNH Form 10-Q for the Quarter Ended June 30, 2008, 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

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)

4.1.1

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)

4.1.2

Third Supplemental Indenture dated as of June 1, 2008, between NU and the Bank of New York Trust Company N.A., as Trustee, relating to $250M of Senior Notes, Series C, due 2013, (Exhibit 4.1 to NU Current Report on Form 8-K filed June 5, 2008, File No. 001-5324)

4.2

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 Current Report on Form 8-K filed 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

Series D 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 Current Report on 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 Current Report on 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 Current Report on 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 Current Report on 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 Current Report on 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 Current Report on Form 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 Current Report on Form 8-K filed September 17, 2007, File No. 0-00404)

4.2.5

Supplemental Indenture (2008 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of May 1, 2008 (Exhibit 4.1 to CL&P Current Report on Form 8-K filed May 27, 2008, 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 (CL&P Pollution Control Revenue Bond - 1996A Series) dated as of January 1, 1997 (Exhibit 4.2.24, 1996 CL&P Form 10-K, File No. 0-00404)

4.8.1

First Amendment to Amended and Restated Loan Agreement, (CL&P Pollution Control Revenue Bond-1996A Series), dated as of October 1, 2008, by and between the Connecticut Development Authority and CL&P (Exhibit 10.1, CL&P Form 10-Q for the Quarter Ended September 30, 2008, 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)

4.9.1

First Amendment to Amended and Restated Indenture of Trust between Connecticut Development Authority and U.S. Bank National Association, as the Trustee, dated as of October 1, 2008 (Exhibit 10.2 CL&P Form 10-Q for the Quarter Ended September 30, 2008, 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

Release Agreement dated as of October 1, 2008, by and among Ambac Assurance Corporation, U.S. Bank National Association, as the Trustee, CL&P, and the Connecticut Development Authority (Exhibit 10, CL&P Form 10-Q for the Quarter Ended September 30, 2008, File No. 0-00404)

4.12

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 Current Report on Form 8-K filed 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 Current Report on Form 8-K filed 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 Current Report on 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 Current Report on 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 Current Report on Form 8-K filed September 24, 2007, File No. 1-6392)

4.1.6

Sixteenth Supplemental Indenture, dated as of May 1, 2008, between PSNH and U.S. Bank National Association, Trustee, relating to First Mortgage Bonds, Series O, due 2018, (Exhibit 4.1 to PSNH Current Report on Form 8-K filed May 27, 2008 (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 Current Report on Form 8-K filed 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 Current Report on 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 Current Report on 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 Current Report on 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 Current Report on 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 Current Report on 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 Current Report on Form 8-K filed December 9, 2005, File No. 0-7624)

10

Material Contracts

(A)

Northeast Utilities

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, filed 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)

10.2.7

Ninth Supplemental Indenture of Mortgage dated as of October 1, 2008 between Yankee Gas Services Company and The Bank of New York Mellon Trust Company, N.A., successor as trustee to The Bank of New York, as successor to Fleet National Bank (formerly known as The Connecticut National Bank), as Trustee (Exhibit 10-1, NU Form 10-Q for the Quarter Ended September 30, 2008, File No. 1-5324)

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*10.3

Summary of Trustee Compensation Arrangement

+

10.4

Amended and Restated Northeast Utilities Deferred Compensation Plan for Trustees, effective January 1, 2009 (Exhibit 10.6, NU Form 10-Q for the Quarter Ended September 30, 2008, 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 Renewal of Service Contract (Exhibit 10.1.2, 2006 NU Form 10-K, File No. 1-5324)

10.2

Agreements among New England Utilities with respect to the Hydro-Québec 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.)

10.3

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)

10.3.1

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)

E-5

10.4

Northeast Utilities Service Company Transmission and Ancillary Service Wholesale Revenue Allocation Methodology, dated as of January 1, 2008 among The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, Holyoke Water Power Company and Holyoke Power and Electric Company Trustee (Exhibit 10.1, NU Form 10-Q for the Quarter Ended March 31, 2008, File No. 1-5324)

+

10.5

Separation Agreement with Cheryl W. Grisé, dated June 22, 2007 (Exhibit 10.20.2, 2008 NU Form 10-K, File No. 1-5324)

+ *

10.6

Amended and Restated Employment Agreement with Charles W. Shivery, effective January 1, 2009

+ *

10.7

Amended and Restated Employment Agreement with Gregory B. Butler, effective January 1, 2009

+ *

10.8

Amended and Restated Employment Agreement with David R. McHale, effective January 1, 2009

+ *

10.9

Amended and Restated Memorandum Agreement between Northeast Utilities and Leon J. Olivier, effective January 1, 2009

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10.10

Amended and Restated Incentive Plan Effective January 1, 2009 (Exhibit 10.3, NU Form 10-Q for the Quarter Ended September 30, 2008, File No. 1-5324)

+

10.11

Amended and Restated Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Company (Exhibit 10.5, 10-Q for the Quarter Ended September 30, 2008, File No. 1-5324)

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10.12

Trust Agreement under Supplemental Executive Retirement Plan dated May 2, 1994 (Exhibit 10.33, 2002 NU Form 10-K, File No. 1-5324)

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10.12.1

First Amendment to Trust Agreement, effective as of December 10, 2002 (Exhibit 10 (B) 10.19.1, 2003 NU Form 10-K, File No. 1-5324)

+ *

10.12.2

Second Amendment to Trust Agreement, effective as of November 12, 2008

+

10.13

Special Severance Program for Officers of NU System Companies, (Exhibit 10.2, NU Form 10-Q for the Quarter Ended September 30, 2008, File No. 1-5324)

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10.14

Amended and Restated Northeast Utilities Deferred Compensation Plan for Executives (Exhibit 10.4 NU Form 10-Q for Quarter Ended September 30, 2008, File No. 1-5324)

10.15

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)

(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

(A)

Northeast Utilities

12

Ratio of Earnings to Fixed Charges

(B)

The Connecticut Light and Power Company

12

Ratio of Earnings to Fixed Charges

(C)

Public Service Company of New Hampshire

12

Ratio of Earnings to Fixed Charges

(D)

Western Massachusetts Electric Company

12

Ratio of Earnings to Fixed Charges

*21

Subsidiaries of the Registrant

*23

Consent of Independent Registered Public Accounting Firm

*31

Rule 13a - 14(a)/15d - 14(a) Certifications

(A)

Northeast Utilities

31

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities 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 27, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Northeast Utilities 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 27, 2009

(B)

The Connecticut Light and Power Company

31

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company 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 27, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company 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 27, 2009

(C)

Public Service Company of New Hampshire

31

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire 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 27, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire 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 27, 2009

(D)

Western Massachusetts Electric Company

31

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company 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 27, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company 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 27, 2009

*32

18 U.S.C. Section 1350 Certifications

(A)

Northeast Utilities

32

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities and David R. McHale, Executive 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 27, 2009

(B)

The Connecticut Light and Power Company

32

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company and David R. McHale, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 27, 2009

(C)

Public Service Company of New Hampshire

32

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire and David R. McHale, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 27, 2009

(D)

Western Massachusetts Electric Company

32

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company and David R. McHale, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 27, 2009