CONNECTICUT LIGHT & POWER CO
Form 10-K
February 26, 2010

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, 2009
OR

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

For the transition period from ____________ to ____________

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

0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

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

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

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

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

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

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

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
	ü

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
ü	

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. [**ü**]

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	ü		
The Connecticut Light and Power Company			ü
Public Service Company of New Hampshire			ü
Western Massachusetts Electric Company			ü

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

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

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, 2009) was **$3,909,588,738** based on a closing sales price of **$22.31** per share for the 175,239,298 common shares outstanding on June 30, 2009. **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 as of January 31, 2010
Northeast Utilities Common shares, $5.00 par value	175,692,984 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, 2010	Part III

GLOSSARY OF TERMS

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

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS

Boulos	E. S. Boulos Company
CL&P	The Connecticut Light and Power Company
HWP	HWP Company, formerly Holyoke Water Power Company
NAESCO	North Atlantic Energy Service Corporation
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company and subsidiaries
NU or the Company	Northeast Utilities and subsidiaries
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, and other subsidiaries, including HWP, The Rocky River Realty Company (a real estate subsidiary), Mode 1 Communications, Inc. (telecommunications) and the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company and Yankee Energy Financial Services Company).
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.
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 Utilities
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
C&LM	Conservation and Load Management
CfD	Contract for Differences
COLA	Cost of Living Adjustment
CTA	Competitive Transition Assessment
CYAPC	Connecticut Yankee Atomic Power Company
EPS	Earnings Per Share
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FMCC	Federally Mandated Congestion Charges
GAAP	Accounting principles generally accepted in the United States of America
GSC	Generation Service Charge
GWh	Gigawatt Hours
IPP	Independent Power Producers
ISO-NE	New England Independent System Operator or ISO New England, Inc.
KV	Kilovolt
KWH or kWh	Kilowatt-hours
LBCB	Lehman Brothers Commercial Bank, Inc.
LNG	Liquefied Natural Gas
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
MWh	Megawatt-hours
MYAPC	Maine Yankee Atomic Power Company
NEEWS	New England East-West Solutions
NU supplemental benefit trust	The NU trust under SERP
NYMPA	New York Municipal Power Agency
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pensions
PCRBs	Pollution Control Revenue Bonds
PPA	Pension Protection Act
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.
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
RSU	Restricted Share Units
RTO	Regional Transmission Organization
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
TCAM	Transmission Cost Adjustment Mechanism
TSO	Transitional Standard Offer
UI	The United Illuminating Company
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:

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actions or inaction by local, state and federal regulatory bodies

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changes in business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products and services

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changes in weather patterns

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changes in laws, regulations or regulatory policy

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changes in levels and timing of capital expenditures

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disruptions in the capital markets or other events that make our access to necessary capital more difficult or costly

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developments in legal or public policy doctrines

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technological developments

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changes in accounting standards and financial reporting regulations

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fluctuations in the value of our remaining competitive electricity positions

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actions of rating agencies, and

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other presently unknown or unforeseen factors.

Other risk factors are detailed in our reports filed with the Securities and Exchange Commission (SEC) and updated from time to time, 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.

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NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

PART I

Item 1.

Business

NU, headquartered in Hartford, Connecticut, is a public utility holding company subject to regulation by 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 utility subsidiaries:

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

Public Service Company of New Hampshire (PSNH), a regulated electric utility which serves residential, commercial and industrial customers in parts of New Hampshire and continues to own generation assets used to serve customers;

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

Yankee Gas Services Company (Yankee Gas), a regulated gas utility which serves residential, commercial and industrial customers in parts of Connecticut.

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

NU also owns certain unregulated businesses through its wholly-owned subsidiary, NU Enterprises, Inc. (NU Enterprises). We have exited most of these businesses. As of December 31, 2009, NU Enterprises remaining business consisted of (i) Select Energy Inc. s few remaining energy wholesale marketing contracts, and (ii) NU Enterprises remaining electrical contracting business.

Although NU, CL&P, PSNH and WMECO each 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 98 percent of our total earnings of $330 million for 2009, with electric distribution (including PSNH s generation activities) representing approximately 41.9 percent, electric transmission representing approximately 49.8 percent, and natural gas distribution representing approximately 6.4 percent. The remaining two percent of our 2009 earnings come from our competitive businesses, which are being wound down. See "Overview - Competitive Businesses" in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, in this Annual Report on Form 10-K.

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 2009 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	Total Operating Companies
Residential	58%
Commercial	34%
Industrial	7%
Other	1%
Total	100%

A summary of changes in the regulated companies retail electric gigawatt-hour (GWh) sales for 2009 as compared to 2008 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 Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)
Residential	(0.7)%	1.5 %	(0.2)%	0.6 %	(1.6)%	0.2 %	(0.7)%	1.2 %
Commercial	(2.9)%	(1.4)%	(1.5)%	(0.7)%	(4.8)%	(3.4)%	(2.8)%	(1.5)%
Industrial	(17.6)%	(16.6)%	(8.2)%	(7.1)%	(11.7)%	(10.9)%	(14.1)%	(13.1)%
Other	(2.5)%	(2.5)%	(3.2)%	(3.2)%	12.7 %	12.7 %	(1.6)%	(1.6)%
Total	(3.8)%	(2.1)%	(2.2)%	(1.4)%	(4.8)%	(3.4)%	(3.5)%	(2.1)%

Retail electric sales in 2009 were lower than 2008 and were significantly impacted by the weather and economic conditions. The spring and summer months in 2009 were significantly cooler than normal and when compared to 2008, the amount of cooling degree days, a unit of measurement used to relate a day's temperature to the energy demands of air conditioning, was approximately 23 percent lower in Connecticut and Western Massachusetts and approximately 22 percent lower in New Hampshire. The negative trend in our sales continues to be most prevalent in the industrial class where many customers have been negatively impacted by the weak economic conditions of our region and nation. We believe the reduction in industrial sales is primarily driven by a reduced number of shifts and days of operations. Commercial sales and residential sales in 2009 were also lower than 2008, although residential sales increased by 1.2 percent over 2008 on a weather-normalized basis. In 2010, we expect economic conditions to continue to affect our customers, and we estimate our retail electric sales across all three states will be approximately 1 percent lower than 2009 on a weather-normalized basis.

Recovery of our distribution revenues, however, is not wholly dependent on sales and it varies between customer classes. About two-thirds of CL&P s and WMECO s distribution revenues and about one-half of PSNH s distribution revenue are recovered through charges, such as the customer charge and demand charge, that are not dependent on overall sales volumes. As compared to other customer classes, a greater portion of residential revenues is recovered through volumetric charges. In contrast to residential rates, a greater portion of commercial and industrial revenues is recovered through fixed charges not dependent on volume. Distribution rates for certain large businesses are structured so that we recover 100 percent of the distribution revenues through non-volumetric charges. In this regard, rate design has significantly mitigated the impact of declining commercial and industrial sales on distribution revenues and earnings.

Our expense related to uncollectible receivable balances (our uncollectibles expense) for all of our regulated companies is influenced by the weak economic conditions of our region, which continue to have a negative effect on our customers. Fluctuations in our uncollectibles expense are mitigated, however, from an earnings perspective because a portion of the total uncollectibles expense for each of the electric distribution companies is allocated to the respective company s energy supply rate and recovered through its tariffs. Additionally, for CL&P and Yankee Gas, write-offs of uncollectible receivable balances attributable to qualified customers under financial or medical duress (or hardship customers) are fully recovered through their respective tariffs. In 2009, our total uncollectibles expense was approximately $21 million higher than 2008 and approximately $19 million of the increase impacted our 2009 earnings. The majority of the $19 million increase was incurred by Yankee Gas and CL&P. In 2010, we expect the uncollectibles expense that impacts earnings to be approximately $12 million lower than it was in 2009 and approximately $10 million of the $12 million improvement is expected to be recognized by Yankee Gas. The anticipated decrease in 2010 uncollectibles expense is based on continued account receivable collection efforts, a decline in overall Yankee Gas revenues as a result of lower natural gas prices, and an expectation that the economic conditions will begin to improve.

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. As of December 31, 2009, 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. CL&P has contracts with two Independent Power Producers (IPPs) to purchase electricity monthly in amounts aggregating approximately 1.5 million MWh per year through March 2015 under one of these contracts and 0.1 million MWh per year through December 2020 under the second contract. CL&P sells the output of these contracts in the spot market operated by the New England Independent System Operator (ISO-NE).

The following table shows the sources of 2009 electric franchise retail revenues for CL&P based on categories of customers:

	CL&P
Residential	62%
Commercial	32%
Industrial	5%
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), systems benefits charge (SBC) and other charges that are assessed on all customers.

The CTA is a charge assessed to recover stranded costs associated with electric restructuring as well as various IPP contracts. The SBC recovers costs associated with various hardship and low income programs as well as payments to municipalities to compensate them for losses in property tax revenue due to decreases in the value of electric generating facilities resulting directly from electric restructuring. The CTA and SBC are annually reconciled to true up to actual costs.

Under state law, all of CL&P's customers are entitled to choose their energy suppliers while CL&P remains 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 the cost to customers through a combined "Generation Service Charge" (GSC) and "Bypassable Federally Mandated Congestion Charge" (BFMCC) on customers' bills. The combined GSC and BFMCC charges for both types of service recover all of the costs of procuring energy from CL&P's wholesale suppliers and are adjusted periodically and reconciled semi-annually in accordance with the directives of the DPUC.

Although more CL&P customers chose competitive energy suppliers in 2009, CL&P continues to supply approximately 50 percent of its customer load at Standard Service rates or Supplier of Last Resort Service rates while the other 50 percent of its customer load has migrated to competitive energy suppliers. The majority of this load migration is from large 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.

Distribution Rates: CL&P implemented new distribution rates in 2009 to reflect the DPUC's 2008 rate decision allowing a $20.1 million annualized increase in distribution rates, effective February 1, 2009.

On January 8, 2010, CL&P filed an application with the DPUC to raise distribution rates by $133.4 million, effective July 1, 2010, and by an additional $44.2 million, effective July 1, 2011. Among other items, CL&P is seeking an increase in its authorized return on equity (ROE) from the current 9.4 percent to 10.5 percent. CL&P proposed that the first year s increase be deferred until January 1, 2011 and that the projected $67 million of deferred revenue from the second half of 2010 be recovered from CL&P customers between January 1, 2011 and June 30, 2012. If approved by the DPUC, the application would require an annualized $210 million increase in distribution rates to take effect on January 1, 2011. However, CL&P believes that as a result of the decline in stranded cost recoveries due to the final amortization of CL&P s rate reduction bonds in December 2010, CL&P s CTA will decline by approximately $230 million on an annualized basis on January 1, 2011, more than offsetting the impact of the distribution rate increase. A DPUC decision in the case is expected in mid-2010.

CL&P has a transmission adjustment clause as part of its rates, which reconciles on a semi-annual basis the transmission revenues billed to customers against the transmission costs of acquiring such services, thereby recovering all of its transmission expenses on a timely basis. (See "Regulated Electric Transmission" in this Item 1, *Business* in this Annual Report on Form 10-K).

For further information on CL&P rates and regulatory actions affecting CL&P, 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.

On December 1, 2009, CL&P filed with the DPUC the results of a three-month dynamic pricing smart meter pilot program that involved nearly 3,000 customers (1,500 residential and 1,500 commercial and industrial (C&I) customers). CL&P plans to file a smart metering and dynamic pricing plan with the DPUC by March 31, 2010. The total cost of the pilot program was approximately $13 million and is being recovered through CL&P FMCC rates.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases energy 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 load 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 contracts in place with various suppliers for all of its Standard Service loads and Supplier of Last Resort Service loads through 2010 and for approximately 60 percent of expected load for 2011 and 20 percent of expected load in 2012.

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. As of December 31, 2009, PSNH furnished retail franchise electric service to approximately 490,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of electricity generation assets. Included in those generation assets is a 50 MW wood-burning generating unit (Northern Wood Power Project) at its Schiller Station in Portsmouth, New Hampshire and approximately 70 MW of hydroelectric generating units. PSNH also has contracts with certain IPPs, the output of which it uses to serve its customer load or sell into the market.

The following table shows the sources of 2009 electric franchise retail revenues based on categories of customers:

	PSNH
Residential	49%
Commercial	39%
Industrial	11%
Other	1%
Total	100%

Rates

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

PSNH s Energy Service (ES) rate recovers PSNH's generation and purchased power costs, including an ROE of 9.81 percent on its generation assets. PSNH defers for future recovery or refund any difference between its ES revenues and the actual costs incurred.

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 files with the NHPUC an ES/SCRC reconciliation filing for the preceding year. The difference between ES/SCRC revenues and ES/SCRC costs are included in the ES/SCRC rate calculation and refunded to/recovered from customers in the subsequent period approved by the NHPUC. The NHPUC s last order, issued in December 2009, had no material impact on PSNH.

The Transmission Cost Adjustment Mechanism (TCAM) allows PSNH to recover on a fully reconciling basis its transmission related costs. The TCAM is adjusted July 1 of each year.

Distribution Rates: In April 2009, PSNH filed an application with the NHPUC seeking a temporary increase of $36.4 million in distribution rates on an annualized basis, effective August 1, 2009, and on June 30, 2009, PSNH filed an application requesting a permanent increase of approximately $51 million on an annualized basis to be effective on August 1, 2009, and another $17 million effective July 1, 2010. The application also requested a regulatory ROE of 10.5 percent. On July 31, 2009, the NHPUC approved a settlement agreement on a temporary rate increase of $25.6 million effective August 1, 2009. PSNH expects a decision on the permanent rate application in mid-2010. Any differences between temporary and permanent rates will be reconciled back to August 1, 2009.

For further information on PSNH s rates and regulatory actions affecting it, 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, a wood-burning unit which replaced one of the three 50 MW coal-fired boiler units at the 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, production tax credits, and avoided CO_2 allowance costs under regulations pursuant to the Regional Greenhouse Gas Initiative (RGGI). 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. Revenue sources exceeded stipulated levels in 2009 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 $13 million of incremental revenues for 2009.

PSNH's customers are entitled to choose competitive energy suppliers, with PSNH providing default energy service under its ES rate for those customers who do not elect to use a third party supplier. Prior to 2009, PSNH experienced only a minimal amount of customer migration. However, PSNH s customer migration levels increased significantly in 2009 as energy costs decreased from their historic high levels. Third party energy suppliers with more pricing flexibility were able to offer electricity supply at lower prices than PSNH. At December 31, 2009, approximately 28.1 percent of PSNH s customers, mostly large commercial and industrial customers, had switched to other energy suppliers. The increased level of migration has caused an increase in the ES rate, as fixed costs must be spread over lower sales volume and a smaller group of customers. The customers that did not switch to a third party supplier, predominately residential and small commercial/industrial customers, are now paying a larger proportion of these fixed costs.

PSNH cannot predict if the upward pressure on ES rates will continue into the future, as future customer migration levels, which are dependent on market prices and supplier alternatives, are uncertain. If future market prices once more exceed the ES rate level, some or all of these customers on third party supply may migrate back to PSNH.

PSNH is constructing its Clean Air Project, a sulfur dioxide and mercury scrubber at its Merrimack coal-fired generation station, currently expected to cost $457 million. The project is expected to be under budget and completed in mid-2012. PSNH will recover all related costs through its ES rates. PSNH has spent approximately $146.8 million on the project to date, of which $119.3 million was capitalized in 2009. Construction of the project was approximately 34 percent complete as of December 31, 2009.

Sources and Availability of Electric Power Supply

During 2009, about 67.7 percent of PSNH s load was met through its own generation, long-term power supply provided pursuant to orders of the NHPUC, and contracts with third parties. The remaining 32.3 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 2010 in a similar manner.

New Hampshire s "Electric Renewable Portfolio Standard Act" establishes renewable portfolio standards (RPS) for electricity sold in the state and requires 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. For each MWh of energy produced from a qualifying resource, the producer will receive one REC. Energy suppliers, like PSNH, purchase RECs from these producers and use them to satisfy the RPS requirements. PSNH also owns renewable sources and uses internally generated RECs in meeting its RPS obligations. To the extent that PSNH is unable to purchase sufficient RECs, it makes 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 recovered by PSNH through its ES rates. For further information, 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.

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, 2009, WMECO furnished retail franchise electric service to approximately 205,000 retail customers in 59 cities and towns in the western third of Massachusetts. WMECO does not own any electricity generating facilities. WMECO has contracts with two IPPs, the output of which WMECO sells into the market.

The following table shows the sources of 2009 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, acquisition of 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 WMECO remains 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 recovers certain costs through various tracking mechanisms in its retail rates, including transmission costs and prudently incurred stranded costs (a portion of which have been financed through securitization by issuing RRBs) with periodic true-up adjustments. The last such adjustment, effective January 1, 2010, resulted in a 3.7 percent increase in customer rates.

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-hours (KWh) sales in compliance with the DPU s July 16, 2008 decision in a generic decoupling docket. We expect a decision from the DPU by the end of 2010.

For further information on WMECO s rates and regulatory actions affecting WMECO, 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.

WMECO is subject to service quality (SQ) metrics that measure safety, reliability and customer service. Any charges incurred for failure to meet such metrics are paid by WMECO to customers through a method approved by the DPU. WMECO will likely be required to pay an assessment charge for its 2009 reliability performance, primarily as a result of a power outage impacting WMECO s Springfield underground service territory in 2009. WMECO has performed at target for other non-storm related reliability metrics. WMECO will file its 2009 SQ results and assessment calculation with the DPU in March 2010.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. The program proposes to involve 1,750 customers in WMECO's service region for a term of six months beginning in April 2011. The total cost of the project is estimated to be $7 million, which would be recovered through rates WMECO would charge to customers. A decision is expected from the DPU in the first half of 2010.

On August 12, 2009, the DPU approved a stipulation agreement between WMECO and the AG concerning WMECO's proposal, under the Massachusetts Green Communities Act (GCA), to install 6 MW of solar energy generation in its service territory at an estimated cost of $41 million. Under the agreement, no more than 3 MW will be commissioned in any one year between 2010 and 2012, the ROE on these assets will be a fully-tracking 9 percent, and the benefits of renewable energy and tax credits will be used to reduce the impact on customer bills. WMECO will need to file an additional application with the DPU if it seeks to develop more than the initial 6 MW under the GCA, which allows for electric utility ownership of up to 50 MW of solar energy generating facilities.

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.

REGULATED GAS DISTRIBUTION   YANKEE GAS SERVICES COMPANY

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 205,000), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in 2009 was 52.5 billion cubic feet (Bcf) compared with 49.8 Bcf in 2008. 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. Yankee Gas also owns a 1.2 Bcf Liquefied Natural Gas (LNG) facility in Waterbury, Connecticut which enables the company to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher.

The following table shows the sources of 2009 and 2008 total gas operating revenues based on categories of customers:

	Yankee Gas	
	2009	2008
Residential	48%	45%
Commercial	31%	29%
Industrial	18%	23%
Other	3%	3%
Total	100%	100%

Yankee Gas earned $21 million in 2009 compared to $27.1 million in 2008. The 2009 results were lower than 2008 due primarily to higher operating costs, partially offset by higher revenues attributable to a 6.9 percent increase in firm natural gas sales. For more information regarding Yankee Gas 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 firm natural gas sales in million cubic feet for Yankee Gas for 2009 and 2008 and the percentage changes in 2009 as compared to 2008 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Firm Natural Gas Sales (mcf)			
	2009	**2008**	**Percent Increase**	**Weather Normalized Percentage (Decrease)/Increase**
Residential	13,562	13,467	0.7%	(1.8)%
Commercial	14,063	12,939	8.7%	6.3 %
Industrial	14,825	13,311	11.3%	10.7 %
Total	42.450	39,717	6.9%	5.0 %

Actual and weather normalized firm natural gas sales in 2009 were higher than 2008. The 2009 results for the commercial and industrial classes have benefitted substantially from the addition of new gas-fired distributed generation in Yankee Gas' service region during the last twelve to fifteen months. Yankee Gas recovers almost half of its total distribution revenues through non-usage charges, and thus, similar to our electric distribution companies, changes in sales have less of an impact on revenues. In 2010, we estimate our total weather normalized firm natural gas sales will be essentially the same as 2009.

On January 6, 2010, the DPUC issued a decision approving Yankee Gas' request to sell its four remaining propane plants that were used to supply gas during peak periods. As a result, in order to meet future supply needs during peak periods, Yankee Gas has initiated a project to construct 16 miles of main gas pipeline between Waterbury, Connecticut and Wallingford, Connecticut and an expansion of the Yankee Gas LNG facility s vaporization output (collectively, the WWL Project), which together are estimated to cost approximately $67 million. The WWL Project will connect the LNG storage facility, which is located in Waterbury, Connecticut and is capable of storing the equivalent of 1.2 Bcf of natural gas, to areas with growing demand. We expect to begin construction on this project in the second quarter of 2010 and complete it by the end of 2011.

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.

Under a settlement of its distribution rate filing with the Connecticut Office of Consumer Counsel and the DPUC s Prosecutorial Division in 2007, Yankee Gas 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 LNG facility, and Yankee Gas was allowed an authorized regulatory ROE of 10.1 percent. Yankee Gas is required to return to customers 100 percent of all earnings in excess of the allowed 10.1 percent regulatory ROE. It has not been necessary for Yankee Gas to return any earnings to customers as its regulatory ROE was 6.6 percent in 2009 and 8.3 percent in 2008. Yankee Gas is considering filing a rate case for new rates with the DPUC.

Sources and Availability of Natural Gas Supply

The DPUC requires that Yankee Gas meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its portfolio to meet customer needs under a design day scenario (defined as the coldest day in 30 years) and under a design year scenario (defined as the average of the four coldest years in the last 30 years). Yankee Gas LNG facility enables Yankee Gas to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher. Yankee Gas on-system stored LNG and underground storage supplies help to meet consumption needs during the coldest days of winter. Yankee Gas obtains its interstate supplies from the three interstate pipelines that currently serve Connecticut: the Algonquin, Tennessee and Iroquois Pipelines. Yankee Gas has long-term firm contracts for capacity on TransCanada Pipelines Limited pipeline, Vector Pipeline, L.P., Tennessee Gas Pipeline, Algonquin Pipeline, and Texas Eastern Transmission, L.P. pipelines. Yankee Gas considers such transportation arrangements adequate for its needs.

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 shared by consumers throughout New England.

Wholesale Transmission Rates

Wholesale transmission revenues are based on formula rates that are approved by the FERC. A significant portion of our transmission revenues comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO which 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 Schedule 21 - NU rate schedules to recover costs of transmission and other transmission-related 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 entire 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 refunded to customers.

FERC ROE Decision

Pursuant to a series of orders issued in 2008, FERC set the base ROE for New England transmission projects at 11.14 percent and provided for certain incentives which could increase the ROE to 13.1 percent. As a result CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects completed by the end of 2008. Certain state regulators and municipal utilities had sought rehearing which was denied by FERC. Connecticut state regulators appealed the order to the D.C. Circuit Court of Appeals which appeal was denied on January 29, 2010.

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; (2) inclusion of 100 percent CWIP costs in rate base; and (3) full recovery of prudently incurred costs if any portion of NEEWS is abandoned for reasons beyond our 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

NEEWS

In October 2008, CL&P and WMECO made state siting filings with the Connecticut Siting Council (CSC) in Connecticut and the Energy Facilities Siting Board (EFSB) in Massachusetts, respectively, for the first and largest component of our New England East-West Solutions (NEEWS) project, the Greater Springfield Reliability Project (GSRP). In October 2009, ISO-NE affirmed the need and need date for GSRP. In Connecticut, hearings have been completed and final briefs were filed in mid-January 2010 with the CSC. We believe a final decision may be received from the CSC as early as March 2010. In Massachusetts, hearings were completed in mid-February 2010 with final briefs expected to be filed in the spring. We expect to receive a final decision from the EFSB in the third quarter of 2010. GSRP, which involves the construction of a 115 kilovolt (KV)/345 KV line from Ludlow, Massachusetts to Bloomfield, Connecticut, is the largest and most complicated project within NEEWS and is expected to cost approximately $714 million if built according to our preferred route configuration. Following decisions from the state siting boards, we expect to commence construction in late 2010 and to 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 estimate CL&P's share of the costs of this project will be approximately $250 million. Municipal consultations concluded in November 2008, and CL&P plans to file its siting application with Connecticut regulators later in 2010, following the completion of ISO-NE s reassessment of the need date and issuance of its regional system plan. We currently expect the project to be placed in service in 2014.

The third major 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 Interstate Reliability Project. This project is currently expected to cost approximately $315 million.

ISO-NE is currently performing an evaluation of all projects in its regional system plan, including the Interstate Reliability Project and the Central Connecticut Reliability Project, and assessing the presently estimated need dates for these projects. We expect ISO-NE s view on need dates for the second and third major NEEWS projects to be updated in the next version of the regional system plan, which we expect to see as a draft during the third quarter of 2010.

Included as part of NEEWS are approximately $211 million of associated reliability related expenditures for projects, over $50 million of which are moving forward through the siting and construction phases and are expected to be completed in advance of the three major projects.

We estimate that CL&P's and WMECO's total capital expenditures for NEEWS will be $1.49 billion. Our current capital expenditure and rate base forecasts assume that all NEEWS projects are completed by the end of 2014. However, the timing and amount of our projected annual capital spending could be affected if receipt of siting approvals is delayed or if the need dates for these projects change through ISO-NE's regional system planning process. During the siting approval process, state regulators may require changes in configuration (including placing some lines underground) 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 of the project beyond our current projections.

HQ Tie Line Project

NU and NSTAR, a major Massachusetts utility that serves the greater Boston area, are jointly planning a new, participant-funded, high voltage direct current transmission line from New Hampshire to Canada (HQ tie line project) where it will interconnect with a transmission line being planned by Hydro-Québec (HQ), a large Canadian utility. Under the proposed arrangement, NU and NSTAR would sell to HQ 1,200 MW of firm electric transmission service over the HQ tie line project in order for HQ to sell and deliver this same amount of firm electric power from Canadian low-carbon energy resources to New England. FERC granted approval of the HQ tie line project structure in May 2009.

We have made significant progress in the design of the HQ tie line project and reached conceptual agreement in the development of Transmission Services Agreement (TSA) with HQ. There are several routing options still under technical review and we expect to resolve them by the end of the first half of 2010. We anticipate that we will be filing the TSA with FERC, which will regulate the tariff charges under the TSA, and the project design with ISO-NE for technical review by mid-2010. In addition, there are a number of state and Federal permits that will be required to site the HQ tie line project and we anticipate filing those applications in 2010 as well. Though contingent on timely siting approvals, we currently expect to begin construction of the line in 2012 and have power flowing in 2015 (which coincides with HQ s planned completion of several new hydro-electric facilities). We estimate NU's share of this project to be $675 million.

In addition, we have started to negotiate a long term power purchase agreement with HQ for power flows over the HQ tie line project. Our intention is to create a power purchase agreement structure that could be offered to other load serving entities in addition to NU and NSTAR. Power purchase agreement terms will be subject to state regulatory approvals and critical to winning state policy maker support for the HQ tie line project. We anticipate these agreements to be filed in 2010 as well.

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 2009, our transmission rate base was approximately $2.6 billion, including approximately $2.1 billion at CL&P, $315 million at PSNH and $183 million at WMECO. We forecast that our total transmission rate base will grow to approximately $4.67 billion by the end of 2014. This increase in transmission rate base is driven by the need to improve the capacity and reliability of our regulated transmission system and the construction of the HQ tie line project.

Based on the 2009 actual and 2010 through 2014 projected capital expenditures, our 2009 actual and 2010 through 2014 projected transmission rate base as of December 31 of each year are as follows:

			As of December 31,			
(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
CL&P transmission	$ 2,099	$ 2,105	$ 2,134	$ 2,318	$ 2,545	$ 2,563
PSNH transmission	315	335	433	530	608	584
WMECO transmission	183	240	429	665	889	851
HQ tie line Project	-	-	-	-	-	675
Total transmission	$ 2,597	$ 2,680	$ 2,996	$ 3,513	$ 4,042	$ 4,673

The projected rate base amounts reflected above assume our projected capital expenditures occur as planned, including capital expenditures of $1.49 billion for CL&P and WMECO in the NEEWS program. Capital expenditures could vary from the projected amounts for the companies and periods above. The continuation of weak economic conditions in the Northeast could impact the timing of our major transmission projects. Most of these capital investment projections, including those for the HQ tie line project, assume timely regulatory approval, which in some cases requires extensive review. Delays in or denials of those approvals could reduce the levels of expenditures and associated rate base projections. 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 our existing electric generation, transmission and distribution systems and our natural gas distribution system. Our consolidated capital expenditures in 2009, including amounts incurred but not paid, cost of removal, allowance for funds used during construction and the capitalized portion of pension expense or income (all of which are non-cash factors in determining rate base), totaled approximately $969.2

million, almost all of which ($916.5 million) was expended by the regulated companies. The capital expenditures of these companies in 2010 are estimated to total approximately $1.09 billion. Of this amount, approximately $441 million is expected to be expended by CL&P, $355 million by PSNH, $119 million by WMECO and $112 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 2010. We expect to evaluate needs beyond 2010 in light of future developments, such as restructuring, industry consolidation, performance and other events. Increases in proposed distribution capital expenditures stem 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 energy 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 are beyond their useful lives, such as old distribution poles, underground primary cables and substation switchgear. Replacement of this equipment is extremely costly.

CL&P s transmission capital expenditures in 2009 totaled approximately $163 million compared to $586.3 million in 2008. The decrease in transmission segment capital expenditures in 2009 as compared with 2008 was primarily due to the completion in 2008 of the major southwest Connecticut transmission projects discussed above. For 2010, CL&P projects transmission capital expenditures of approximately $136 million. During the period 2010 through 2014, CL&P plans to invest approximately $1.06 billion 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 2009, CL&P's distribution capital expenditures totaled approximately $283 million. CL&P projects its distribution capital expenditures in 2010 to be approximately $305 million. CL&P plans to spend approximately $1.55 billion on distribution projects during the period 2010 through 2014. 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 $2.1 billion at the end of 2009 to approximately $2.56 billion by the end of 2014, and its rate base for distribution assets is projected to increase from approximately $2.1 billion to approximately $2.91 billion over the same period.

In 2009, PSNH's transmission capital expenditures totaled approximately $61.1 million, its distribution capital expenditures totaled $98.8 million and its generation capital expenditures totaled $145 million. For 2010, PSNH projects transmission capital expenditures of approximately $55 million, distribution capital expenditures of approximately $113 million and generation capital expenditures of approximately $187 million. The increase in generation capital expenditures is mostly due to the expenditures for the Merrimack Clean Air Project. During the period 2010 through 2014, PSNH plans to spend approximately $376 million on transmission projects, approximately $594 million on distribution projects, and $480 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 $315 million at the end of 2009 to approximately $584 million by the end of 2014, and its rate base for distribution and generation assets is projected to increase from approximately $1.18 billion to approximately $2.0 billion over the same period.

In 2009, WMECO's transmission capital expenditures totaled approximately $67.7 million and its distribution capital expenditures totaled approximately $37.7 million. In 2010, WMECO projects transmission capital expenditures of approximately $66 million, distribution capital expenditures of approximately $33 million and $20 million on solar generation. During the period 2010 through 2014, WMECO plans to spend approximately $812 million on transmission projects, with the bulk of that amount to be spent on the NEEWS Greater Springfield Reliability Project, approximately $179 million on distribution projects and $41 million on solar generation. If all of the generation, distribution and transmission projects are built as proposed, WMECO s rate base for electric transmission is projected to increase from approximately $183 million at the end of 2009 to approximately $851 million by the end of 2014 and its rate base for distribution and generation assets is projected to increase from approximately $412 million to approximately $486 million over the same period.

In 2009, Yankee Gas capital expenditures totaled approximately $59.6 million. For 2010, Yankee Gas projects total capital expenditures of approximately $112 million. During the period 2010 through 2014, Yankee Gas plans on making approximately $461 million of capital expenditures, including approximately $62.7 million on the WWL Project and the expansion of the Yankee Gas LNG plant's vaporization output. If all of Yankee Gas projects are built as proposed, Yankee Gas investment in its regulated assets is projected to increase from approximately $691 million at the end of 2009 to approximately $974 million by the end of 2014.

Projected Capital Expenditures: A summary of the capital expenditures for the regulated companies' transmission and the distribution and generation segments, by company, for 2009, and projections for 2010 through 2014, including our corporate service companies' capital expenditures on behalf of the regulated companies, is as follows:

	Year						
(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2010-2014 Totals**
CL&P transmission	$ 163	$ 136	$ 203	$ 281	$ 286	$ 155	$ 1,061
PSNH transmission	61	55	118	107	74	22	376
WMECO transmission	68	66	256	328	156	6	812
HQ tie line Project	-	16	49	90	236	282	673
Subtotal transmission	$ 292	$ 273	$ 626	$ 806	$ 752	$ 465	$ 2,922
CL&P distribution	283	305	313	306	305	317	1,546
PSNH distribution	99	113	111	115	121	134	594
WMECO distribution	38	33	39	36	35	36	179
Subtotal electric distribution	$ 420	$ 451	$ 463	$ 457	$ 461	$ 487	$ 2,319
PSNH generation	145	187	117	82	68	26	480
WMECO generation	-	20	14	7	-	-	41
Subtotal generation	$ 145	$ 207	$ 131	$ 89	$ 68	$ 26	$ 521
Yankee Gas distribution	60	112	104	80	82	83	461
Corporate service companies	52	48	25	22	25	14	134
Totals	$ 969	$ 1,091	$ 1,349	$ 1,454	$ 1,388	$ 1,075	$ 6,357

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 COMPETITIVE ENERGY BUSINESSES

Since 2005, we have been in the process of exiting our competitive energy businesses and are now focusing predominantly on our regulated businesses. At December 31, 2009, our competitive businesses consisted of (i) Select Energy s few remaining wholesale energy marketing contracts, and NGS and its affiliates, which are winding down, and (ii) Boulos, NU Enterprises remaining active electrical contracting business.

Select Energy s wholesale energy contract with The New York Municipal Power Agency (NYMPA) and related energy supply contracts expire in 2013. In addition to the NYMPA contract, Select Energy's only other long-term wholesale obligation is a contract to operate and purchase the output of a generating facility in New England through mid-2012.

For more information regarding our exit from competitive businesses, see "NU Enterprises Divestitures" under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations,* and Note 1B, "Summary of Significant Accounting Policies   Presentation," to the Consolidated Financial Statements, in this Annual Report on Form 10-K.

FINANCING

We paid common dividends of $162.4 million in 2009, compared with $129.1 million in 2008. The increase is the result of increases of 6.3 percent and 11.8 percent in our common dividend rate that took effect in the third quarter of 2008 and in the first quarter of 2009, respectively, and a higher number of shares outstanding in the second, third and fourth quarters of 2009. On February 9, 2010, our Board of Trustees declared a common dividend of $0.25625 per share, ($1.025 on an annual basis) payable on March 31, 2010 to shareholders of record as of March 1, 2010 representing an increase of approximately 7.9 percent over the 2009 dividend rate.

We target paying out approximately 50 percent of consolidated earnings in the form of common dividends. Our ability to pay common dividends is subject to approval by our Board of Trustees and our future earnings and cash flow requirements and may be limited by certain state statutes, the leverage restrictions in our revolving credit agreement and the ability of our subsidiaries to pay common dividends to NU. The Federal Power Act limits 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 of retained earnings under its FERC hydroelectric license conditions. Relevant state statutes may impose additional limitations on the payment of dividends by the regulated companies. CL&P, PSNH, WMECO and Yankee Gas also are parties to a revolving credit agreement that imposes leverage restrictions.

In general, the regulated companies pay approximately 60 percent of their earnings to NU parent in the form of common dividends. In 2009, CL&P, PSNH, WMECO, and Yankee Gas paid $113.8 million, $40.8 million, $18.2 million, and $19.1 million, respectively, in common dividends to NU parent. In 2009, NU parent made equity contributions of $147.6 million, $68.9 million, $0.9 million and $2.7 million to CL&P, PSNH, WMECO and Yankee Gas, respectively.

During 2009, the NU companies issued an aggregate of $462 million of debt, as follows:

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CL&P issued $250 million of first mortgage bonds on February 13, 2009 with an interest rate of 5.5 percent and maturity date of February 1, 2019.

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CL&P remarketed $62 million of Pollution Control Revenue Bonds on April 2, 2009 which it had repurchased and had been holding since 2008. The bonds carry a coupon of 5.25 percent and are subject to a mandatory tender for purchase on April 1, 2010, at which time they will be remarketed.

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PSNH issued $150 million of first mortgage bonds on December 14, 2009 with an interest rate of 4.5 percent and a maturity date of December 1, 2019.

As a result of Lehman Brothers Commercial Bank, Inc. (LBCB) refusing to continue to fund its commitment of approximately $56 million under our credit facilities in 2008 described below, our aggregate borrowing capacity under our credit facilities was reduced from $900 million to $844 million. This borrowing capacity, when combined with our access to other funding sources, provides us with adequate liquidity.

NU parent has a credit facility in a nominal aggregate amount of $500 million, $482.3 million excluding the commitment of LBCB, which expires on November 6, 2010. As of December 31, 2009, NU parent had $41 million of letters of credit (LOCs) issued for the benefit of certain subsidiaries (primarily PSNH) and $100.3 million of borrowings outstanding under this facility. The weighted-average interest rate on these short-term borrowings as of December 31, 2009 was 0.63 percent, which is based on a variable rate plus an applicable margin based on NU parent's credit ratings.

The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million, $361.8 million excluding the commitment of LBCB, which also expires on November 6, 2010. There were no borrowings outstanding under this facility as of December 31, 2009.

Our credit facilities and bond indentures require that NU parent and certain of its subsidiaries, including CL&P, PSNH and WMECO, comply with certain financial and non-financial covenants as are customarily included in such agreements, including maintaining a ratio of consolidated debt to total capitalization of no more than 65 percent. All such companies currently are, and expect to remain in compliance with these covenants.

While we expect to renew our credit facilities in November, 2010, costs associated with the new facilities are likely to be higher than those associated with the existing credit facilities due to market conditions.

We are planning long-term debt issuances in 2010 aggregating approximately $145 million with $95 million being issued by WMECO and $50 million being issued by Yankee Gas. The proceeds from these financings will be used primarily to repay short-term borrowings and fund our capital programs. On January 22, 2010, the DPUC approved WMECO s application to issue and sell up to $150 million of senior secured or unsecured long-term debt.

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 stockholders in three inactive regional nuclear generation 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 generation 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 CL&P, PSNH and WMECO and several other New England utilities. 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**
CYAPC	34.5%	5.0%	9.5%	49.0%
MYAPC	12.0%	5.0%	3.0%	20.0%
YAEC	24.5%	7.0%	7.0%	38.5%

Our share of the obligations to support the Yankee Companies under FERC-approved contracts 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.

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, which has jurisdiction over CL&P and Yankee Gas, the NHPUC, which has jurisdiction over PSNH, and the DPU, which has 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 approximately 1,200 MW of generation assets in New Hampshire and is spending approximately $457 million to install a wet flue gas desulphurization system at Merrimack Station (Clean Air Project) to reduce its mercury and sulfur dioxide emissions. 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. The need to comply 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 Federal Clean Air Act Amendments of 1990 (CAAA), as well as New Hampshire law, impose stringent requirements on emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Installation of continuous emissions monitors and expanded permitting provisions also are included.

In New Hampshire, the Multiple Pollutant Reduction Program capped NO_X, $SO_2$and carbon dioxide (CO_2) emissions 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 SO_2 emissions as well). The Clean Air Project addresses this requirement. PSNH began site work for this project in November 2008, which is scheduled to be completed by mid-2012.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the RGGI, a cooperative effort by ten northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fuel-fired electric generating plants. Because CO_2 allowances issued by any participating state will be usable across all ten RGGI state programs, the individual state CO_2 trading programs, in the aggregate, will form one regional compliance market for CO_2 emissions. A regulated power plant must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of a three-year compliance period that began in 2009.

Because neither CL&P nor WMECO own any generating assets, neither is required to acquire CO_2 allowances; however, the CO_2 allowance costs borne by generators which provide energy supply to CL&P and WMECO will likely be included in wholesale rates charged to them, which costs will be recoverable from customers.

PSNH anticipates that its generating units will emit between 4 million and 5 million tons of CO_2 per year after taking into effect the operation of PSNH s Northern Wood Power Project. Under the RGGI formula, this Project 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 through 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. 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 secondary market. The cost of complying with RGGI requirements is recoverable from PSNH customers.

Each of the states in which we do business also has RPS requirements, which generally require fixed percentages of energy supply to come from renewable energy sources such as solar, hydropower, landfill gas, fuel cells and other similar sources. New Hampshire s RPS provision requires increasing percentages of the electricity PSNH sells to its retail customers to have direct ties to renewable sources, beginning in 2008 at 4 percent and ultimately reaching 23.8 percent by 2025. We expect that the additional costs incurred to meet this requirement will be recovered through PSNH s energy service rates. Connecticut's RPS statutes require that a specific

percentage of the energy provided to Connecticut consumers be produced from renewable energy sources. Beginning with a 4 percent requirement in 2004, the requirement increases each year. For 2009, the requirement was 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. Any costs incurred in complying with RPS would be passed on to customers through rates.

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

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws were implemented, residues from operations were often disposed of by depositing or burying such materials on-site or disposing of them at off-site landfills or facilities. Typical materials disposed of include coal gasification waste, fuel oils, ash, gasoline and other hazardous materials that might contain polychlorinated biphenyls. It has since been determined that deposited or buried wastes, under certain circumstances, could cause groundwater contamination or create other environmental risks. We have recorded a liability for what we believe is, based upon currently available information, our estimated environmental investigation and/or remediation costs for waste disposal sites for which we expect to bear legal liability. We 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, 2009, the liability recorded by us for our reasonably estimable and probable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $26 million, representing 57 sites. These costs could be significantly higher if remediation becomes 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 $26 million, a reserve of approximately $24.1 million has been established to address future investigation and/or remediation costs at MGP sites.

HWP Company (HWP), formerly known as Holyoke Water Power Company, 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 an 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.

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 HWP commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP has developed and implemented site characterization studies to further delineate tar deposits 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.

HWP first established a reserve for this site in 1994. The cumulative expense recorded to this reserve through December 31, 2009 was approximately $17 million, of which $15.9 million had been spent, leaving approximately $1.1 million in the reserve as of December 31, 2009. At this time, we believe that the $1.1 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $1.1 million to $1.8 million and will be sufficient for HWP to evaluate the results of the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. There are many outcomes that could affect our estimates and require an increase to the reserve for HWP s costs on this matter, 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, the extent of remediation required by the DEP 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 7A, "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.

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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.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues have received an increased focus from state governments and the federal government, particularly in the last year. The U.S. Environmental Protection Agency (EPA) has initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" and endanger public health and welfare and should be regulated. The largest source of greenhouse gas emissions in the U.S. is the electricity generating sector.

We are continually evaluating the risks presented by climate change concerns and issues. Such concerns could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the generating facilities we own and operate as well as general utility operations. (See "Air Quality Requirements" in this section for information concerning RGGI) These could include federal cap and trade laws, or regulations requiring additional capital expenditures at our generating facilities. In addition, such rules or regulations could potentially impact the prices we pay for goods and services provided by companies directly affected by such rules or regulations. We would expect that any costs of these rules and regulations would be recovered from customers, but such costs could impact energy use by our customers.

Global climate change could potentially impact weather patterns such as increasing the frequency and severity of storms or altering temperatures. These changes could affect our facilities and infrastructure and could also impact energy usage by our customers.

FERC Hydroelectric Project Licensing

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 a current claimed capability representing winter rates of approximately 71 MW, eight of which are licensed by the FERC under long-term licenses that expire on varying dates from 2017 through 2047. As a licensee under the Federal Power Act (FPA), PSNH and its 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.

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.

EMPLOYEES

As of December 31, 2009, we employed a total of 6,078 employees, excluding temporary employees, of which 1,870 were employed by CL&P, 1,250 by PSNH, 348 by WMECO, 425 by Yankee Gas and 2,185 were employed by Northeast Utilities Service Company (NUSCO). Approximately 2,231 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are members of the International Brotherhood of Electrical Workers and The United Steelworkers and are covered by 11 union agreements.

INTERNET INFORMATION

Our website address is www.nu.com. We make available through our website a link to the SEC's EDGAR website (http://www.sec.gov/edgar/searchedgar/companysearch.html), 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, 56 Prospect Street, Hartford, CT 06103.

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 actions of regulators can significantly affect our earnings, liquidity and business activities.

The rates that our regulated companies charge their respective retail and wholesale customers are determined by their state utility commissions and by FERC. These commissions also regulate the companies accounting, operations, the issuance of certain securities and certain other matters. FERC also regulates their transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain matters. The commissions policies and regulatory actions could have a material impact on the regulated companies financial position, results of operations and liquidity.

Our transmission and distribution systems may not operate as expected, and could require unplanned expenditures which could adversely affect our earnings and cash flows.

The ability to manage the operations of 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 high percentage of our regulated company equipment, such as distribution poles, underground primary cables and substation switchgear is old or obsolete, or nearing or at the end of its life cycle. The failure of our transmission and distributions systems to operate as planned may result in increased capital investments, reduced earnings or unplanned increases in operation and maintenance costs. Such costs which are not recoverable from our customers would have an adverse effect on our earnings.

Limits on our access to capital may adversely impact our ability to execute our business plan.

We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not obtained from our operating cash flow. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy could be adversely affected. Events beyond our control, such as the disruption in global capital and credit markets in 2008, or a downgrade of our credit ratings, could increase our cost of borrowing and cost of capital or restrict our ability to access the capital markets and negatively affect our ability to maintain and to expand our businesses.

Our counterparties may not meet their obligations to us.

We are exposed to the risk that counterparties to various arrangements who owe us money, or contracted to supply us with energy, coal, or other commodities or services, will not be able to perform their obligations or, with respect to our credit facilities, fail to honor their commitments. Should the counterparties to commodity arrangements fail to perform their obligations, we might be forced to replace the underlying commitment at higher market prices. Should any more lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements could decrease. In such an event, our results of operations, financial position, or liquidity could be adversely affected.

Changes in regulatory or legislative policy and/or regulatory decisions, difficulties in obtaining siting, design or other approvals, global demand for critical resources, environmental or other concerns, or construction of new generation may delay completion of or displace our planned 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 could be affected by new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions, delays in obtaining approvals or difficulty in obtaining critical resources required for construction. Any of such events could cause delays in our construction schedule adversely affecting 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, our planned transmission projects may be delayed or displaced, which could result in reduced transmission capital investments, reduced earnings, and limited future growth prospects.

Many of our 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, focus on conservation and self-generation by customers and changes in legislative and regulatory policy may adversely impact our business.

Energy consumption is significantly impacted by the general level of economic activity and cost of energy supply. Economic downturns such as the one which began in 2008, or periods of high energy supply costs typically lead to reductions in energy consumption and increased 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. A period of prolonged economic weakness could impact customers ability to pay bills in a timely manner and increase customer bankruptcies, which may lead to increased bad debt expenses or other adverse effects on our results of operations, cash flows or financial position.

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 investigated 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 fixed charges, and proportionately less distribution revenue through usage-based charges. In New Hampshire, the NHPUC conducted a decoupling docket and determined that utilities were free to propose decoupling in the context of a rate case and demonstrate the effect decoupling would have on its risk profile and ROE. In Massachusetts, the DPU conducted a generic decoupling docket and as a result required each utility to include rate decoupling in its next rate case. 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 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 their regional costs across New England. This regional cost allocation is set forth in the Transmission Operating Agreement signed by all of the New England transmission owning utilities. However, effective February 1, 2010, this agreement can be modified with the approval of a majority of the transmission owning utilities and FERC. In addition, 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. However, the current cost allocation is presumed reasonable, and those other parties seeking change would have to show that the allocation is no longer just and reasonable and demonstrate to FERC why such changes are necessary. 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 or unfavorable outcomes in regulatory proceedings could jeopardize our full and/or timely recovery of costs incurred by our regulated 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 construction, operation and maintenance, 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 needs 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 the 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 and fixed-price forward purchase contracts. PSNH s remaining energy needs are met primarily through spot market 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 is building 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 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 forecasted levels of earnings. 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 have developed 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, including cyber-terrorism could negatively impact the operation of our system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results of operations.

Severe weather, such as ice and snow storms, hurricanes and other natural disasters, may cause outages and property damage which may require us to incur additional costs that 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.

Market performance or changes in assumptions could require us to make significant contributions to our pension and other post-employment benefit plans.

We provide a defined benefit pension plan and other post-retirement benefits for a substantial number of employees, former employees and retirees. The measurement of our expected future pension obligations, costs and liabilities is highly dependent on a variety of assumptions, most of which relate to factors beyond our control. These assumptions include investment returns, interest rates, health care cost trends, benefit improvements, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs could increase significantly. In addition, various factors, including underperformance of plan investments, could increase the amount of contributions required to fund our pension plan in the future. Large funding requirements, when combined with the financing requirements of our construction program, could impact the timing and amount of future equity and debt financings and would negatively affect our financial position, cash flows and results of operations.

Costs of compliance with environmental regulations, including climate change legislation, 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 govern, 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 our results of operations, financial position and cash flows.

In addition, global climate change issues have received an increased focus from federal and state governments, 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 customers, their impact on energy use by customers and the ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time. The impact of these additional costs to customers could lead to a further reduction in energy consumption resulting in a decline in electricity and gas sales in our service territories, which would have an adverse impact on our business and results of operations, financial position and cash flows.

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. The cost impact of any such laws, rules or regulations 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" in this Annual Report on Form 10-K.

As a holding company with no revenue-generating operations, NU parent is dependent on dividends from its subsidiaries, primarily the regulated companies, its bank facility, and its ability to access the long-term debt and equity capital markets.

NU parent is a holding company and as such, has no revenue-generating operations of its own. Its ability to meet its financial obligations associated with the debt service obligations on its debt and to pay dividends on its common shares is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily the regulated companies; the ability of its subsidiaries to pay dividends or to repay funds due NU parent; and/or NU parent s ability to access its credit facility or the long-term debt and equity capital markets. Prior to funding NU parent, the regulated companies have financial obligations that must be satisfied, including among others, their respective debt service, preferred dividends (in the case of CL&P) and obligations to trade creditors. Additionally, the regulated companies could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from NU parent. Should the regulated companies not be able to pay dividends or repay funds due to NU parent or if NU parent cannot access its bank facilities or the long-term debt and equity capital markets, NU parent s ability to pay interest and dividends would be restricted.

Item 1B.

Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2.

Properties

Transmission and Distribution System

As of December 31, 2009, our electric operating subsidiaries owned 31 transmission and 432 distribution substations that had an aggregate transformer capacity of 4,462,000 kilovolt amperes (kVa) and 29,811,000 kVa, respectively; 3,098 circuit miles of overhead transmission lines ranging from 69 KV to 345 KV, and 433 cable miles of underground transmission lines ranging from 69 KV to 345 KV; 34,935 pole miles of overhead and 2,999 conduit bank miles of underground distribution lines; and 538,032 underground and overhead line transformers in service with an aggregate capacity of 36,968,352 kVa.

Electric Generating Plants

As of December 31, 2009, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (megawatts)
Total - Fossil-Steam Plants	(5 units)	1952-74	932
Total - Hydro-Conventional	(20 units)	1901-83	71
Total Biomass Steam Plant	(1 unit)	1954	46
Total - Internal Combustion	(5 units)	1968-70	103
Total PSNH Generating Plant	(31 units)		1,152

*

Claimed capability represents winter ratings as of December 31, 2009. The combined nameplate capacity of the generating plants is approximately 1,200 MW.

Neither CL&P nor WMECO owned any electric generating plants during 2009.

Yankee Gas

As of December 31, 2009, Yankee Gas owned 28 active gate stations, approximately 200 district regulator stations and 3,200 miles of gas main pipelines. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut as well as a propane facility in Kensington, Connecticut.

Franchises

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

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

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

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

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

The Massachusetts restructuring legislation defines service territories as those territories actually served on July 1, 1997 and following municipal boundaries to the extent possible. The restructuring legislation further provides that until terminated by law or otherwise, distribution companies shall have the exclusive obligation to serve all retail customers within their service territories and no other person shall provide distribution service within such service territories without the written consent of such distribution companies. Pursuant to the Massachusetts restructuring legislation, the DPU (then, the Department of Telecommunications and Energy) was required to define service territories for each distribution company, including WMECO. The 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.

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 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 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 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 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

In September 2006, CL&P and Yankee Gas (the NU Companies) filed a complaint against UGI Utilities, Inc. (UGI) in the U.S. District Court for the District of Connecticut seeking past and future remediation costs related to historic manufactured gas plant (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 allege 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. A trial was held in April 2009.

On May 22, 2009, the court granted judgment in favor of the NU Companies with respect to the Waterbury-North site, and granted judgment in favor of UGI with respect to the remaining sites. On June 19, 2009, the NU Companies filed a Notice of Appeal with respect to the court s decision. Any recovery resulting from the case (following the appeal) would flow back to the NU Companies customers, and the NU companies would continue to seek recovery as appropriate of remediation and other associated costs with regard to the sites for which no recovery from UGI will be forthcoming.

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.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the executive officers of NU as of February 25, 2010. All of the Company s officers serve terms of one year and until their successors are elected and qualified:

Name	**Age**	**Title**
Jay S. Buth*	40	Vice President Accounting and Controller.
Gregory B. Butler	52	Senior Vice President and General Counsel.
Jean M. LaVecchia**	58	Vice President - Human Resources of Northeast Utilities Service Company (NUSCO), a subsidiary of NU.
David R. McHale	49	Executive Vice President and Chief Financial Officer of NU.
Leon J. Olivier	61	Executive Vice President and Chief Operating Officer of NU.
James B. Robb**	49	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	64	Chairman of the Board, President and Chief Executive Officer of NU.

*

Mr. Buth was elected Vice President Accounting and Controller, effective June 9, 2009.

**

Deemed executive officer of NU pursuant to Rule 3b-7 under the Securities Exchange Act of 1934.

Jay S. Buth. Mr. Buth became Vice President Accounting and Controller of NU, CL&P, PSNH and WMECO, effective June 9, 2009. Previously, Mr. Buth served as Controller, and Vice President and Controller at NJR Service Corporation, a subsidiary of New Jersey Resources Corporation, a gas utility holding company, from June 2006 to January 2009. He also served as Director - Finance at Allegheny Energy, Inc. from May 2004 to May 2006.

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 CL&P, PSNH and WMECO April 22, 2009 and 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.

Jean M. LaVecchia. Ms. LaVecchia was elected Vice President - Human Resources of NUSCO, effective January 1, 2005 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009 and 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 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.

James B. Robb. Mr. Robb was elected Senior Vice President, Enterprise Planning and Development of NUSCO on September 4, 2007 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009. 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.

Item 4.

[RESERVED]

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 quarter, are shown below.

Year	**Quarter**	**High**	**Low**
2009	First	$ 25.05	$ 19.45
	Second	22.40	19.99
	Third	24.72	21.38
	Fourth	26.33	22.54
2008	First	$ 31.15	$ 24.01
	Second	27.74	25.12
	Third	28.03	24.52
	Fourth	25.97	19.15

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, 2009.

As of January 31, 2010, there were 42,273 common shareholders of our company on record. As of the same date, there were a total of 195,503,401 common shares issued, including 102,281 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.

On February 9, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on March 31, 2010 to shareholders of record as of March 1, 2010.

On October 13, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on December 31, 2009 to shareholders of record as of December 1, 2009.

On July 14, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on September 30, 2009 to shareholders of record as of September 1, 2009.

On April 14, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on June 30, 2009 to shareholders of record as of June 1, 2009.

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.

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 2009 and 2008, CL&P approved and paid $113.8 million and $106.5 million, respectively, of common stock dividends to NU.

During 2009 and 2008, PSNH approved and paid $40.8 million and $36.4 million, respectively, of common stock dividends to NU.

During 2009 and 2008, WMECO approved and paid $18.2 million and $39.7 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 Stockholder Matters*, included in this Annual Report on Form 10-K.

Item 6.

Selected Consolidated Financial Data

NU Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and share information)		**2009**		**2008**		**2007**		**2006**		**2005**
Balance Sheet Data:										
Property, Plant and Equipment, Net	$	8,839,965	$	8,207,876	$	7,229,945	$	6,242,186	$	6,417,230
Total Assets		14,057,679		13,988,480		11,581,822		11,303,236		12,567,875
Total Capitalization (a)		8,253,323		7,293,960		6,667,920		5,879,691		5,595,405
Obligations Under Capital Leases (a)		12,873		13,397		14,743		14,425		13,987
Income Data:										
Operating Revenues	$	5,439,430	$	5,800,095	$	5,822,226	$	6,877,687	$	7,346,226
Income/(Loss) from Continuing Operations		335,592		266,387		251,455		138,495		(251,344)
Income from Discontinued Operations		-		-		587		337,642		4,420
Income/(Loss) Before Cumulative Effects of Accounting Changes, Net of Tax Benefits		335,592		266,387		252,042		476,137		(246,924)
Cumulative Effects of Accounting Changes, Net of Tax Benefits		-		-		-		-		(1,005)
Net Income/(Loss) Attributable to Noncontrolling Interest		5,559		5,559		5,559		5,559		5,559
Net Income/(Loss) Attributable to Controlling Interest	$	330,033	$	260,828	$	246,483	$	470,578	$	(253,488)
Common Share Data:										
Basic Earnings/(Loss) Per Common Share:										
Income/(Loss) from Continuing Operations Attributable to	$	1.91	$	1.68	$	1.59	$	0.86	$	(1.95)

Controlling Interest Income from Discontinued Operations Attributable to Controlling Interest		-		-		-		2.20		0.03
Cumulative Effects of Accounting Changes, Net of Tax Benefits		-		-		-		-		(0.01)
Net Income/(Loss) Attributable to Controlling Interest	$	1.91	$	1.68	$	1.59	$	3.06	$	(1.93)
Fully Diluted Earnings/(Loss) Per Common Share:										
Income/(Loss) from Continuing Operations Attributable to Controlling Interest	$	1.91	$	1.67	$	1.59	$	0.86	$	(1.95)
Income from Discontinued Operations Attributable to Controlling Interest		-		-		-		2.19		0.03
Cumulative Effects of Accounting Changes, Net of Tax Benefits		-		-		-		-		(0.01)
Net Income/(Loss) Attributable to Controlling Interest	$	1.91	$	1.67	$	1.59	$	3.05	$	(1.93)
Basic Common Shares Outstanding (Average)		172,567,928		155,531,846		154,759,727		153,767,527		131,638,953
Fully Diluted Common Shares Outstanding (Average)		172,717,246		155,999,240		155,304,361		154,146,669		131,638,953
Dividends Per Share	$	0.95	$	0.83	$	0.78	$	0.73	$	0.68
Market Price - Closing (high) (b)	$	26.33	$	31.15	$	33.53	$	28.81	$	21.79
Market Price - Closing (low) (b)	$	19.45	$	19.15	$	26.93	$	19.24	$	17.61
Market Price - Closing (end of year) (b)	$	25.79	$	24.06	$	31.31	$	28.16	$	19.69
Book Value Per Share (end of year)	$	20.37	$	19.38	$	18.79	$	18.14	$	15.85
Tangible Book Value Per Share (end of year) (c)	$	18.74	$	17.54	$	16.93	$	16.28	$	13.98
Rate of Return Earned on Average Common Equity (%) (d)		10.2		8.8		8.6		18.0		(10.7)
		1.3		1.2		1.7		1.6		1.2

Market-to-Book Ratio (end of year) (e)					
Capitalization:					
Common Shareholders Equity	44 %	41 %	44 %	48 %	43 %
Preferred Stock, not subject to mandatory redemption	1	2	2	2	2
Long-Term Debt (a)	55	57	54	50	55
	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.

(c)

Common Shareholder's Equity adjusted for goodwill and intangibles divided by total common shares outstanding.

(d)

Net Income divided by the average change in Common Shareholder's Equity.

(e)

The closing market price divided by the book value per share.

See the *Combined Notes to the Consolidated Financial Statements* for a description of any accounting changes materially affecting the comparability of the information reflected in the table above**.**

CL&P Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2009	2008	2007	2006	2005
Operating Revenues	$ 3,424,538	$ 3,558,361	$ 3,681,817	$ 3,979,811	$ 3,466,420
Net Income	216,316	191,158	133,564	200,007	94,845
Cash Dividends on Common Stock	113,848	106,461	79,181	63,732	53,834
Property, Plant and Equipment, net	5,340,561	5,089,124	4,401,846	3,634,370	3,166,692
Total Assets	8,364,564	8,336,118	7,018,099	6,321,294	5,765,072
Rate Reduction Bonds	195,587	378,195	548,686	743,899	856,479
Long-Term Debt (a)	2,582,361	2,270,414	2,028,546	1,519,440	1,258,883
Preferred Stock, not subject to mandatory redemption	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	10,956	11,207	13,602	14,264	13,488

PSNH Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2009	2008	2007	2006	2005
Operating Revenues	$ 1,109,591	$ 1,141,202	$ 1,083,072	$ 1,140,900	$ 1,128,427
Net Income	65,570	58,067	54,434	35,323	41,739
Cash Dividends on Common Stock	40,844	36,376	30,720	41,741	42,383
Property, Plant and Equipment, net	1,814,714	1,580,985	1,388,405	1,242,378	1,155,423
Total Assets	2,697,191	2,628,833	2,106,969	2,071,276	2,294,583
Rate Reduction Bonds	188,113	235,139	282,018	333,831	382,692
Long-Term Debt (a)	836,255	686,779	576,997	507,099	507,086
Obligations Under Capital Leases (a)	1,670	1,931	1,141	1,356	498

WMECO Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2009	2008	2007	2006	2005
Operating Revenues	$ 402,413	$ 441,527	$ 464,745	$ 431,509	$ 409,393
Net Income	26,196	18,330	23,604	15,644	15,085
Cash Dividends on Common Stock	18,203	39,706	12,779	7,946	7,685
Property, Plant and Equipment, net	705,760	624,205	559,357	526,094	499,317
Total Assets	1,101,800	1,048,489	991,088	988,693	945,996
Rate Reduction Bonds	58,735	73,176	86,731	99,428	111,331

Long-Term Debt (a)	305,475	303,868	303,872	261,777	259,487
Obligations Under Capital Leases (a)	105	126	-	-	-

(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," the Company, "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 and earnings per share (EPS) of each business discussed below do not represent a direct legal interest in the assets and liabilities allocated to such business but rather represent a direct interest in our assets and liabilities as a whole. EPS by business is a financial 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 attributable to controlling interest of each business by the weighted average fully diluted NU common shares outstanding for the period. We use this non-GAAP financial measure to evaluate earnings results and to provide details of earnings results and guidance by business. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our businesses. This non-GAAP financial 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 financial measures referencing our 2008 earnings and EPS excluding a significant charge resulting from the settlement of litigation. We use these non-GAAP financial measures to more fully compare and explain the 2009, 2008 and 2007 results without including the impact of this settlement. Due to the nature and significance of the litigation settlement charge to Net income, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to readers of this report in analyzing historical and future performance. These non-GAAP financial measures should not be considered as alternatives to reported Net income attributable to controlling interest or EPS determined in accordance with GAAP as indicators of operating performance.

Reconciliations of the above non-GAAP financial measures to the most directly comparable GAAP measures of consolidated fully diluted EPS and Net income attributable to controlling interest are included under "Financial Condition and Business Analysis-Overview-Consolidated" and "Financial Condition and Business Analysis-Future Outlook" in *Management's Discussion and Analysis*, herein.

Financial Condition and Business Analysis

Executive Summary

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

Results, Strategy and Outlook:

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We earned $330 million, or $1.91 per share, in 2009, compared with $260.8 million, or $1.67 per share, in 2008. Excluding the after-tax charge of $29.8 million, or $0.19 per share, for the settlement of litigation, we earned $290.6 million, or $1.86 per share, in 2008. The increase in 2009 results was due primarily to a $34.4 million increase in earnings from our regulated distribution and transmission segments. The EPS for 2009 reflected the issuance of approximately 19 million common shares on March 20, 2009.

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Our regulated companies, which consist of The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), and Yankee Gas Services Company (Yankee Gas), earned $323.5 million, or $1.87 per share, in 2009, compared with $289.1 million, or $1.85 per share, in 2008.

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Earnings at the distribution segments of our regulated companies (which also include Yankee Gas and the generation business of PSNH) totaled $159.2 million in 2009, compared with $150.8 million in 2008. Earnings at the transmission segments of our regulated companies totaled $164.3 million in 2009, compared with $138.3 million in 2008. The increase in distribution segment results was due primarily to lower operating costs as a result of cost management efforts, lower storm costs, distribution rate increases at CL&P and PSNH, higher generation-related earnings and the absence of a $3.5 million after-tax charge recorded in 2008 that related to the refund of the 2004 procurement incentive fee. The higher transmission segment results were due to an increased investment in transmission infrastructure after the completion of major projects in 2008.

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Our competitive businesses, which are held by NU Enterprises, Inc. (NU Enterprises), earned $15.8 million, or $0.09 per share, in 2009, compared with $13.1 million, or $0.08 per share, in 2008. The after-tax mark-to-market gain on wholesale marketing contracts increased by $2.7 million from $1.1 million in 2008 to $3.8 million in 2009. The 2008 mark-to-market included a net after-tax charge of $3.2 million due to the implementation of fair value measurement accounting guidance.

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NU parent and other companies recorded net expenses of $9.3 million, or $0.05 per share, in 2009, compared with net expenses of $41.4 million, or $0.26 per share, in 2008. Results for 2008 included the after-tax charge of $29.8 million, or $0.19 per share, associated with the settlement of litigation.

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We project consolidated 2010 earnings of between $1.80 per share and $2.00 per share, including distribution segment earnings of between $0.95 per share and $1.05 per share, transmission segment earnings of between $0.90 per share and $0.95 per share, competitive business earnings of between zero and $0.05 per share, and net expenses at NU parent and other companies of approximately $0.05 per share. PSNH filed a distribution rate case in June 2009 and CL&P filed a distribution rate case in

January 2010. There are uncertainties over the outcomes of these distribution rate cases, both of which are expected to conclude in mid-2010. WMECO intends to file a distribution rate case in mid-2010 with an expected decision by the end of 2010 and a distribution rate case filing for Yankee Gas is also under consideration, neither of which are included in the 2010 projections.

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We paid common dividends of $162.4 million in 2009, compared with $129.1 million in 2008. The increase is the result of 6.3 percent and 11.8 percent increases that took effect in the third quarter of 2008 and the first quarter of 2009, respectively, and a higher number of shares outstanding in the second, third and fourth quarters of 2009.

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We project that we will achieve a compound average annual EPS growth rate for the five-year period from 2010 to 2014 of between 6 percent and 9 percent, using 2009 EPS of $1.91 as the base level.

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Regulated company capital expenditures are expected to total approximately $6.4 billion from 2010 through 2014, which would enable our total rate base to grow at a compound average annual growth rate of 9.5 percent from approximately $7 billion at the end of 2009 to $11.1 billion at the end of 2014. This projection assumes the projects we have included in our five-year plan are built according to our schedule and on budget. Significant projects included in the plan are the CL&P and WMECO New England East-West Solutions (NEEWS) project, the PSNH Clean Air Project, the Hydro-Québec (HQ) tie line project, and the Yankee Gas Waterbury to Wallingford Pipeline Project.

Legal, Regulatory and Other Items:

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On May 22, 2009, the Federal Energy Regulatory Commission (FERC) granted approval of the structure of a proposed project between NU, NSTAR, a Massachusetts utility company that serves the greater Boston area, and HQ, a large Canadian utility, involving a high voltage direct current (HVDC) transmission line from New Hampshire to Canada (HQ tie line project) to deliver and sell 1,200 megawatts (MW) of low-carbon energy in New England.

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On June 30, 2009, PSNH filed an application with the New Hampshire Public Utilities Commission (NHPUC) requesting a permanent increase in distribution rates of approximately $51 million on an annualized basis to be effective August 1, 2009, and another $17 million to be effective July 1, 2010. On July 31, 2009, the NHPUC approved a temporary increase in distribution rates of $25.6 million on an annualized basis, effective August 1, 2009. PSNH expects a decision on the permanent distribution rate request in mid-2010. Any differences between allowed temporary rates and permanent rates will be reconciled back to August 1, 2009.

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On August 12, 2009, the Massachusetts Department of Public Utilities (DPU) approved the installation of 6 MW of solar energy generation in WMECO's service territory at an estimated cost of $41 million. The return on equity (ROE) on these assets will be a fully tracking 9 percent.

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On January 8, 2010, CL&P filed an application with the Connecticut Department of Public Utility Control (DPUC) to raise distribution rates by $133.4 million to be effective July 1, 2010, and by an additional $44.2 million to be effective July 1, 2011. CL&P proposed that the first year s increase would be deferred until January 1, 2011 and that approximately $67 million of cash revenue requirement for the second half of 2010 would be deferred and recovered from CL&P customers between January 1, 2011 and June 30, 2012. A DPUC decision on this rate application is expected in mid-2010.

Liquidity:

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NU completed a public offering of approximately 19 million common shares on March 20, 2009, resulting in $370.8 million of net proceeds to the Company after offering expenses of $12.5 million. The proceeds were used to fund capital investment programs for our regulated companies and to repay short-term borrowings. We anticipate a single public offering of approximately $300 million in NU common shares in the next five years, which is expected no earlier than 2012.

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We issued $462 million of debt in 2009 ($312 million at CL&P and $150 million at PSNH), comprised of $400 million in first mortgage bonds at rates of 4.5 percent and 5.5 percent, and $62 million in remarketed pollution control revenue bonds (PCRBs) at a one-year fixed rate of 5.25 percent. We expect to issue an aggregate amount of approximately $145 million of long-term debt in the first half of 2010 ($95 million at WMECO and $50 million at Yankee Gas).

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We had total outstanding long-term and short-term debt of approximately $4.7 billion as of December 31, 2009, compared with approximately $4.8 billion as of December 31, 2008. The decline reflects a reduction of approximately $520 million in notes payable to banks, partially offset by approximately $400 million in increases to long-term debt. The decline in total debt was due primarily to increased cash flows from operations and the sale by NU of approximately 19 million common shares.

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Our cash capital expenditures totaled $908.1 million in 2009, compared with $1.3 billion in 2008. The decrease in our cash capital expenditures was primarily the result of lower transmission segment capital expenditures, particularly at CL&P, due to the completion in 2008 of three major transmission projects in southwest Connecticut. We project total capital expenditures of approximately $1.1 billion in 2010 (including non-cash factors) due to higher expenditures for NEEWS and other regulated company projects.

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After rate reduction bond (RRB) payments included in financing activities, we had cash flows provided by operating activities in 2009 of $745 million, which represented an increase of approximately $321 million from 2008. The improved cash flows were due primarily to higher transmission revenues at CL&P; approximately $225 million more in cash collected in 2009 compared to 2008 for costs that are tracked and passed on to customers; approximately $100 million less in cash expenditures on fuel, materials and supplies in 2009 (largely due to lower amounts spent for Yankee Gas storage due to lower natural gas prices); and the absence in 2009 of the litigation settlement payment of $49.5 million made in March 2008.

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We project consolidated cash flows provided by operating activities, net of RRB payments, of approximately $4 billion from 2010 through 2014, ranging from approximately $700 million in 2010 to approximately $1.1 billion in 2014. This projection reflects a cash contribution of approximately $45 million into the Company s pension plan in the third quarter of 2010, as well as a potential contribution in 2011 of approximately $200 million.

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Our cash and cash equivalents totaled $27 million as of December 31, 2009, compared with $89.8 million as of December 31, 2008. As of December 31, 2009, we also had $702.8 million of aggregate borrowing availability on our revolving credit lines, as compared to $157.8 million of availability as of December 31, 2008. This increase in availability was primarily a result of the 2009 equity and debt issuances, higher cash flows provided by operating activities and lower capital expenditures. Our credit facilities in a total nominal amount of $900 million will expire on November 6, 2010. While we expect to renew these facilities before the expiration date, costs associated with the new facilities will likely be higher than those associated with the existing credit facilities due to changes in credit market conditions.

Overview

Consolidated: We earned $330 million, or $1.91 per share, in 2009, compared with $260.8 million, or $1.67 per share, in 2008 and $246.5 million, or $1.59 per share, in 2007. Excluding the after-tax charge of $29.8 million, or $0.19 per share, for the settlement of litigation, we earned $290.6 million, or $1.86 per share, in 2008. The increase in 2009 results was due primarily to a $34.4 million increase in earnings from our regulated distribution and transmission segments, which includes their shares of the resolution of several routine income tax audits that increased NU earnings in 2009 and 2008 by $13.8 million and $8.9 million, respectively. The EPS for 2009 reflected the issuance of approximately 19 million common shares on March 20, 2009. A summary of our earnings by business, which also reconciles the non-GAAP financial measures of consolidated non-GAAP earnings and EPS, as well as EPS by business, to the most directly comparable GAAP measures of consolidated net income attributable to controlling interest and fully diluted EPS, for 2009, 2008 and 2007 is as follows:

(Millions of Dollars, except per share amounts)	For the Years Ended December 31, 2009 Amount	2009 Per Share	2008 Amount	2008 Per Share	2007 Amount	2007 Per Share
Net income attributable to controlling interest (GAAP)	$ 330.0	$ 1.91	$ 260.8	$ 1.67	$ 246.5	$ 1.59
Regulated companies	$ 323.5	$ 1.87	$ 289.1	$ 1.85	$ 228.7	$ 1.47
Competitive businesses	15.8	0.09	13.1	0.08	11.7	0.08
NU parent and other companies	(9.3)	(0.05)	(11.6)	(0.07)	6.1	0.04
Non-GAAP earnings	330.0	1.91	290.6	1.86	246.5	1.59
Litigation charge (after-tax)	-	-	(29.8)	(0.19)	-	-
Net income attributable to controlling interest (GAAP)	$ 330.0	$ 1.91	$ 260.8	$ 1.67	$ 246.5	$ 1.59

Regulated Companies: Our regulated companies operate in two segments: electric transmission and electric and gas distribution, with PSNH generation included in its distribution segment. A summary of regulated company earnings by segment for 2009, 2008 and 2007 is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2009	2008	2007
CL&P Transmission	$ 136.8	$ 115.6	$ 66.7
PSNH Transmission	18.0	16.7	10.7
WMECO Transmission	9.5	6.0	5.1
Total Transmission	$ 164.3	$ 138.3	$ 82.5
CL&P Distribution	$ 74.0	$ 70.0	$ 61.4
PSNH Distribution	47.5	41.4	43.7
WMECO Distribution	16.7	12.3	18.5
Yankee Gas	21.0	27.1	22.6
Total Distribution	$ 159.2	$ 150.8	$ 146.2
Net Income - Regulated Companies	$ 323.5	$ 289.1	$ 228.7

The higher 2009 and 2008 transmission segment earnings reflect an increased investment in this segment as we continued to build out our transmission infrastructure to meet our customers' and the region's reliability needs. The results primarily reflect the effect of CL&P's investment of approximately $1.6 billion since the beginning of 2005 in the southwest Connecticut transmission projects that were completed in late 2008. Our transmission segment rate base has increased from approximately $1.5 billion as of December 31, 2007 to approximately $2.6 billion as of December 31, 2009.

CL&P s 2009 distribution segment earnings were $4 million higher than 2008 due primarily to lower operating costs as a result of cost management efforts, lower storm costs, higher distribution revenues resulting from distribution rate increases effective February 1st in both 2008 and 2009, gains from the NU supplemental benefit trust, and the absence of a $5.8 million pre-tax charge recorded in 2008 that related to the refund of the 2004 procurement incentive fee. Partially offsetting these favorable variances were higher expenses related to uncollectible receivable balances, higher pension costs, increased depreciation as a result of greater plant balances in service and greater income taxes as a result of a higher effective income tax rate. CL&P s retail electric sales in 2009 were 3.8 percent lower than 2008. CL&P s distribution segment regulatory ROE was 7.3 percent in 2009, well below its current authorized level of 9.4 percent, and 7.5 percent in 2008. We expect CL&P s regulatory ROE to continue to deteriorate before it improves starting in the second half of 2010 when we anticipate the DPUC will issue a decision on CL&P s request to raise its distribution rates effective July 1, 2010. CL&P s request includes an authorized regulatory ROE of 10.5 percent.

PSNH s 2009 distribution segment earnings were $6.1 million higher than 2008. The increase in 2009 is due primarily to higher generation-related earnings, higher revenues attributable to the temporary distribution rate increase effective August 1, 2009, lower carrying costs as a result of significant decreases in energy service regulatory obligations owed to customers, and gains from the NU supplemental benefit trust, all of which were partially offset by higher pension costs, increased depreciation as a result of greater plant balances in service, increased amortization costs, higher property taxes as a result of both a larger taxable base and increased local municipal tax rates, and greater income taxes as a result of a higher effective income tax rate. PSNH s retail electric sales in 2009 were 2.2 percent lower than 2008. PSNH s distribution segment regulatory ROE was 7.2 percent in 2009 (including generation), which reflects a regulatory ROE for the distribution business of 3.6 percent compared with its current authorized level of 9.67 percent. In 2008, PSNH's distribution segment regulatory ROE was 8.3 percent and the regulatory ROE for the distribution business was 6.3 percent. We expect PSNH s regulatory ROE to continue to deteriorate before it improves starting in the second half of 2010 when we anticipate the NHPUC will issue a decision on PSNH s permanent distribution rate request. PSNH s request includes an authorized regulatory ROE of 10.5 percent for its distribution business.

WMECO s 2009 distribution segment earnings were $4.4 million higher than 2008 due primarily to lower operating costs as a result of cost management efforts, lower storm costs, gains from the NU supplemental benefit trust, and the absence of a $1.6 million pre-tax charge recorded in 2008 related to a DPU ruling. These positive factors were partially offset by higher property taxes as a result of both a greater asset base and increased local municipal tax rates, increased depreciation as a result of greater plant in service balances, increased amortization, and a 4.8 percent decline in retail electric sales. WMECO s distribution segment regulatory ROE was 8.4 percent in 2009 and 7.2 percent in 2008. We expect WMECO s distribution segment regulatory ROE will be approximately 6 percent in 2010.

Yankee Gas 2009 earnings were $6.1 million lower than 2008 due primarily to higher operating costs including expenses related to uncollectible receivable balances, employee benefits, and depreciation, partially offset by higher revenues attributable to a 6.9 percent increase in firm natural gas sales and the absence of a $5.8 million pre-tax charge recorded in 2008 for refunds of previous gas cost recoveries. Yankee Gas regulatory ROE was 6.6 percent in 2009, due primarily to higher uncollectible expenses, and 8.3 percent in 2008. Yankee Gas' authorized regulatory ROE is 10.1 percent. We expect Yankee Gas regulatory ROE will be approximately 9 percent in 2010 due primarily to results from improved collection efforts of customer receivables and higher distribution revenues.

For the distribution segment of our regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric gigawatt-hour (GWh) sales and Yankee Gas firm natural gas sales for 2009 as compared to 2008 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 Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Pe I
Residential	(0.7)%	1.5 %	(0.2)%	0.6 %	(1.6)%	0.2 %	(0.7)%	1.2 %	
Commercial	(2.9)%	(1.4)%	(1.5)%	(0.7)%	(4.8)%	(3.4)%	(2.8)%	(1.5)%	
Industrial	(17.6)%	(16.6)%	(8.2)%	(7.1)%	(11.7)%	(10.9)%	(14.1)%	(13.1)%	
Other	(2.5)%	(2.5)%	(3.2)%	(3.2)%	12.7 %	12.7 %	(1.6)%	(1.6)%	
Total	(3.8)%	(2.1)%	(2.2)%	(1.4)%	(4.8)%	(3.4)%	(3.5)%	(2.1)%	

A summary of our retail electric sales in GWh for CL&P, PSNH and WMECO and firm natural gas sales in million cubic feet for Yankee Gas for 2009 and 2008 is as follows:

	Electric			Firm Natural Gas		
	2009	2008	Percentage Decrease	2009	2008	Percentage Increase
Residential	14,412	14,509	(0.7)%	13,562	13,467	0.7%
Commercial	14,474	14,885	(2.8)%	14,063	12,939	8.7%
Industrial	4,423	5,149	(14.1)%	14,825	13,311	11.3%
Other	336	340	(1.6)%	-	-	-
Total	33,645	34,883	(3.5)%	42,450	39,717	6.9%

Actual retail electric sales in 2009 were lower than 2008 and were significantly impacted by the weather and economic conditions. The spring and summer months in 2009 were significantly cooler than normal and when compared to 2008, the amount of cooling degree days was approximately 23 percent lower in Connecticut and Western Massachusetts and approximately 22 percent lower in New Hampshire. The negative trend in our sales continues to be most prevalent in the industrial class where many customers have been negatively impacted by the weak economic conditions of our region and nation. We believe the reduction in industrial sales is primarily driven by a reduced number of shifts and days of operations. Commercial sales and residential sales in 2009 were also lower than 2008, although residential sales increased by 1.2 percent over 2008 on a weather-normalized basis. In 2010, we expect the economic conditions to continue to affect our customers and on a weather normalized basis, we estimate our retail electric sales, across all three states, will be approximately 1 percent lower than 2009.

Recovery of our distribution revenues, however, is not wholly dependent on sales and it varies between customer classes. About two-thirds of CL&P s and WMECO s distribution revenues and about one-half of PSNH s distribution revenues are recovered through charges, such as the customer charge and demand charge, that are not dependent on overall sales volumes. As compared to other customer classes, a greater portion of residential revenues is recovered through volumetric charges. In contrast to residential rates, a much smaller portion of commercial and industrial revenues is recovered through volumetric charges. Distribution rates for certain large businesses are structured so that we recover 100 percent of the distribution revenues through non-volumetric charges. In this regard, rate design has significantly mitigated the impact of the declining commercial and industrial sales on distribution revenues and earnings.

Actual and weather normalized firm natural gas sales in 2009 were higher than 2008. The 2009 results have improved due to an increase in customers and, for the commercial and industrial sectors, have benefited substantially from the addition of new gas-fired distributed generation in Yankee Gas' service region during the last fifteen to eighteen months ended December 31, 2009. Yankee Gas recovers almost half of its total distribution revenues through non-usage charges, and thus, similar to our electric distribution companies, changes in sales have less of an impact on revenues. In 2010, we estimate our total weather normalized firm natural gas sales will be essentially the same as 2009, but the change will vary for each customer class.

Our expense related to uncollectible receivable balances (our uncollectibles expense) is influenced by the economic conditions of our region and the weak conditions in the Northeast continue to have a negative effect on our customers. Fluctuations in our uncollectibles expense are mitigated, however, from an earnings perspective because a portion of the total uncollectibles expense for each of the electric distribution companies is allocated to the respective company s energy supply rate and recovered through its tariffs. Additionally, for CL&P and Yankee Gas, write-offs of uncollectible receivable balances attributable to qualified customers under financial or medical duress (or hardship customers) are fully recovered through their respective tariffs. In 2009, our total uncollectibles expense was approximately $21 million higher than 2008 and approximately $19 million of the increase impacted our 2009 earnings. The majority of the $19 million increase was incurred by Yankee Gas and CL&P. In 2010, we expect the uncollectibles expense that impacts earnings to be approximately $12 million lower than it was in 2009 and approximately $10 million of the $12 million improvement is expected to be recognized by Yankee Gas. The anticipated decrease in 2010 uncollectibles expense is based on continued account receivable collection efforts, a small decline in overall Yankee Gas revenues as a result of lower natural gas prices, and an expectation that the economic conditions will begin to improve.

Competitive Businesses: NU Enterprises, which continues to manage to completion Select Energy, Inc.'s (Select Energy) remaining wholesale marketing contracts and to manage its electrical contracting business, earned $15.8 million, or $0.09 per share, in 2009, compared with $13.1 million, or $0.08 per share, in 2008 and $11.7 million, or $0.08 per share, in 2007. Competitive business earnings in 2009 included an after-tax mark-to-market gain of $3.8 million associated with Select Energy s wholesale marketing contracts, as compared to a $1.1 million after-tax mark-to-market gain in 2008 and a $3.8 million after-tax mark-to-market loss in 2007. The mark-to-market gain in 2008 included a net after-tax charge to Net income of $3.2 million associated with the implementation of accounting guidance for fair value measurements. Results for NU Enterprises are not expected to continue at the earnings levels of the past three years, as the margins Select Energy earns on its remaining contracts are expected to decline in future years. We project that NU Enterprises will earn between zero and $0.05 per share in 2010.

NU Parent and Other Companies: NU parent and other companies recorded net expenses of $9.3 million, or $0.05 per share, in 2009, compared with net expenses of $41.4 million, or $0.26 per share, in 2008 and net income of $6.1 million, or $0.04 per share, in 2007. The net expenses in 2008 included a $29.8 million, or $0.19 per share, after-tax charge resulting from the payment of $49.5 million made in March 2008 associated with the settlement of litigation. Excluding the charge, the 2009 net expenses decreased by $2.3 million as compared to 2008 due primarily to a favorable return on equity investments and lower interest expense. Net income in 2007 included interest income for NU parent on a higher level of cash received from the sale of our competitive generation business in late 2006.

Future Outlook

EPS Guidance: A summary of our projected 2010 EPS by business, which also reconciles consolidated fully diluted EPS to the non-GAAP financial measures of EPS by business, is as follows:

	2010 EPS Range			
(Approximate amounts)		**Low**		**High**
Fully Diluted EPS (GAAP)	$	1.80	$	2.00
Regulated companies:				
Distribution segment	$	0.95	$	1.05
Transmission segment		0.90		0.95
Total regulated companies		1.85		2.00
Competitive businesses		-		0.05
NU parent and other companies		(0.05)		(0.05)
Fully Diluted EPS (GAAP)	$	1.80	$	2.00

We have included estimated impacts from current economic conditions in the assumptions that were used to develop our earnings guidance. The 2010 distribution segment guidance reflects an assumed one percent annual decrease in total weather-normalized retail electric sales, a decrease in Yankee Gas' uncollectibles expense, and uncertainty around the outcomes of the PSNH distribution rate case that was filed in June 2009 and the CL&P distribution rate case filed in January 2010. Both the PSNH and CL&P rate case decisions are expected in mid-2010.

A WMECO distribution rate case is expected to be filed in mid-2010 with a decision expected by the end of 2010. A Yankee Gas rate case filing is also being considered. Additional earnings from the WMECO and Yankee Gas filings are not included in the above projections.

In 2009, the NU effective tax rate was 34.9 percent. For 2010, we estimate that the effective tax rate for NU will be approximately 34 percent.

Long-Term Growth Rate: We project that we will achieve a compound average annual EPS growth rate for the five-year period from 2010 to 2014 of between 6 percent and 9 percent, using 2009 EPS of $1.91 as the base level. This EPS growth rate assumes regulatory ROEs averaging approximately 12.25 percent for the transmission segment and an average of approximately 10 percent for the distribution segment (including PSNH and WMECO generation). We believe this growth will be achieved if our capital program is completed in accordance with our plans, distribution rate case orders enable us to earn the assumed level of regulatory ROEs, and FERC's current transmission policies remain consistent and enable us to achieve projected transmission ROEs. In addition to the assumptions above, there are certain items that will likely impact this earnings growth rate. These items include, but are not limited to, sales levels; operating expense levels, including maintenance, pension and uncollectibles expense; and lower margins that NU Enterprises expects to earn on Select Energy s remaining contracts.

Liquidity

Consolidated: We had $27 million of cash and cash equivalents as of December 31, 2009, compared with $89.8 million as of December 31, 2008. The combined borrowings and letters of credit (LOCs) outstanding on our revolving credit facilities totaled $141.3 million as of December 31, 2009, compared with approximately $706 million as of December 31, 2008. The decrease in short-term borrowings was primarily a result of higher cash flows provided by operating activities, lower capital expenditures, the issuance of approximately 19 million common shares by NU on March 20, 2009, which yielded net proceeds of $370.8 million after offering expenses of $12.5 million, and total 2009 debt issuances of $462 million.

On February 13, 2009, CL&P issued $250 million of first mortgage bonds due February 1, 2019 and carrying a coupon of 5.5 percent. On December 14, 2009, PSNH issued $150 million of first mortgage bonds due December 1, 2019 and carrying a coupon of 4.5 percent. Proceeds from these issuances were used to repay short-term debt and fund capital expenditures.

On April 1, 2009, using funds borrowed from the NU Money Pool, Yankee Gas retired $50 million of first mortgage bonds carrying a coupon of 6.2 percent that were issued in January 1999.

On April 2, 2009, CL&P remarketed $62 million of tax-exempt PCRBs it had elected to acquire in October 2008. The PCRBs, which mature on May 1, 2031, carry a coupon of 5.25 percent during the current fixed-rate period that ends on the mandatory tender purchase date of April 1, 2010, at which time CL&P expects to remarket the bonds with a new coupon rate set through an auction process.

Our planned financings for 2010 total approximately $145 million of new long-term debt to be issued in the first half of the year comprised of $95 million at WMECO and $50 million at Yankee Gas. We have only annual sinking fund requirements of $4.3 million continuing in 2010 through 2012, the mandatory tender of $62 million of PCRBs by CL&P in April 2010, and no debt maturities until April 1, 2012. The proceeds from our 2010 financings will be used primarily to repay short-term borrowings and fund our capital programs.

On January 22, 2010, the DPU approved WMECO's application to issue and sell up to $150 million of senior secured or unsecured long-term debt, and WMECO continues to assess whether to issue secured or unsecured debt. If WMECO decides to issue first mortgage bonds, then WMECO will be obligated to secure its $195 million of currently outstanding senior unsecured notes equally and ratably with such first mortgage bonds.

We had total outstanding long-term and short-term debt of approximately $4.7 billion as of December 31, 2009, compared with approximately $4.8 billion as of December 31, 2008. The decline reflects a reduction of approximately $520 million in notes payable to banks, partially offset by approximately $400 million in increases to long-term debt. The decline in total debt was due primarily to increased cash flows from operations and the sale of approximately 19 million common shares.

We had positive cash flows provided by operating activities in 2009 of $745 million, compared with positive operating cash flows of $424.1 million in 2008 and negative operating cash flows of $5.7 million in 2007 (all amounts are net of RRB payments, which are included in financing activities). The improved cash flows in 2009 were due primarily to higher transmission revenues at CL&P after significant projects were placed in service in late 2008, as well as cost management efforts; a decrease of approximately $225 million related primarily to amounts spent on CL&P's Federally Mandated Congestion Charge (FMCC) and Generation Service Charge (GSC), the costs of which are passed on to customers; approximately $100 million less in cash expenditures on fuel, materials and supplies in 2009 due primarily to the lower cost of gas being stored by Yankee Gas for the winter heating season; and the absence in 2009 of the litigation settlement payment of $49.5 million made in 2008. A cash flow increase due to improved collections of accounts receivable in 2009 was more than offset by increased payments in 2009 from storm costs from December 2008. The increase in operating cash flows from 2007 to 2008 was due primarily to the absence in 2008 of approximately $400 million in tax payments made in 2007 related to the 2006 sale of the Company s former competitive generation business.

We project consolidated cash flows provided by operating activities of approximately $4 billion from 2010 through 2014, net of RRB payments, ranging from approximately $700 million in 2010 to approximately $1.1 billion in 2014, assuming our capital projects are completed as expected and we receive fair regulatory treatment on related expenditures. We expect the vast majority of our capital programs to be funded through cash flows provided by operating activities and new debt issuances and currently anticipate a single NU common share issuance in the next five years of approximately $300 million, which is expected no earlier than 2012. The projection for 2010 operating cash flows reflects a cash contribution of approximately $45 million, the majority of which will be funded by PSNH, into the Company s pension plan in the third quarter of 2010 as described under "Liquidity-Impact of Financial Market Conditions" in this *Management's Discussion and Analysis*. This contribution will be the first contribution into the Company s pension plan in approximately 20 years. In addition, we will potentially contribute approximately $200 million into our pension plan in 2011.

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 senior unsecured debt of NU parent and WMECO and senior secured debt of

CL&P and PSNH is as follows:

	Moody's		S&P		Fitch	
	Current	**Outlook**	**Current**	**Outlook**	**Current**	**Outlook**
NU parent	Baa2	Stable	BBB-	Stable	BBB	Stable
CL&P	A2	Stable	BBB+	Stable	A-	Stable
PSNH	A3	Stable	BBB+	Stable	BBB+	Stable
WMECO	Baa2	Stable	BBB	Stable	BBB+	Stable

In August 2009, Moody s completed an industry-wide review of the number of levels between utility first mortgage bonds and utility unsecured debt. Moody s stated that its review of utility credit defaults showed a much higher rate of recovery for first mortgage bonds than for unsecured debt. The review resulted in one-level upgrades of CL&P and PSNH first mortgage bonds by Moody s. In the second half of 2009, subsequent to those upgrades, all three rating agencies reaffirmed all of their existing credit ratings and stable outlooks on NU parent, CL&P, PSNH and WMECO. On January 22, 2010, Fitch downgraded CL&P s preferred stock rating from BBB to BBB- as a result of revised guidelines for rating preferred stock and hybrid securities in general.

If NU parent's senior unsecured debt ratings were to be reduced to below 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 LOCs. If such an event had occurred as of December 31, 2009, Select Energy, under its remaining contracts, would have been required to provide additional cash or LOCs in an aggregate amount of $29.8 million to various unaffiliated counterparties and additional cash or LOCs in the aggregate amount of $8.6 million to independent system operators. NU parent would have been and remains able to provide that collateral on behalf of Select Energy.

We paid common dividends of $162.4 million in 2009, compared with $129.1 million in 2008 and $121 million in 2007. The increase from 2007 to 2009 is the result of a 6.7 percent increase in our common dividend rate that took effect in the third quarter of 2007, additional 6.3 percent and 11.8 percent increases that took effect in the third quarter of 2008 and first quarter of 2009, respectively, and a higher number of shares outstanding in the second, third and fourth quarters of 2009. On February 9, 2010, our Board of Trustees declared a quarterly common dividend of $0.25625 per share, payable on March 31, 2010 to shareholders of record as of March 1, 2010, which represents a 7.9 percent increase from the quarterly 2009 common dividend rate. The new annualized rate of $1.025 per share represents an increase of $0.075 per share above the previous annualized rate of $0.95 per share.

We target paying out approximately 50 percent of consolidated earnings in the form of common dividends. Our ability to pay common dividends is subject to approval by our Board of Trustees and our future earnings and cash flow requirements and may be limited by certain state statutes, the leverage restrictions in our revolving credit agreement and the ability of our subsidiaries to pay common dividends to NU parent. The Federal Power Act limits the payment of dividends by CL&P, PSNH and WMECO to their respective

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retained earnings balances unless a higher amount is approved by FERC; PSNH is required to reserve an additional amount of retained earnings under its FERC hydroelectric license conditions. In addition, relevant state statutes may impose additional limitations on the payment of dividends by the regulated companies. CL&P, PSNH, WMECO and Yankee Gas also are parties to a revolving credit agreement that imposes leverage restrictions.

In general, the regulated companies pay approximately 60 percent of their earnings to NU parent in the form of common dividends. In 2009, CL&P, PSNH, WMECO, and Yankee Gas paid $113.8 million, $40.8 million, $18.2 million, and $19.1 million, respectively, in common dividends to NU parent. In 2009, NU parent made equity contributions of $147.6 million, $68.9 million, $0.9 million and $2.7 million to CL&P, PSNH, WMECO and Yankee Gas, respectively.

Cash capital expenditures included on the accompanying consolidated statements of cash flows and described in this "Liquidity" section do not include amounts incurred on capital projects but not yet paid, cost of removal, the allowance for funds used during construction (AFUDC) related to equity funds, and the capitalized portions of pension and postretirement benefits other than pension (PBOP) expense or income. A summary of our cash capital expenditures by company for the years ended December 31, 2009, 2008 and 2007 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars)		**2009**		**2008**		**2007**
CL&P	$	435.7	$	849.5	$	826.2
PSNH		266.4		238.9		167.7
WMECO		105.4		78.3		47.3
Yankee Gas		54.8		58.3		57.6
Other		45.8		30.4		16.0
Totals	$	908.1	$	1,255.4	$	1,114.8

The decrease in our total cash capital expenditures was primarily the result of lower transmission segment capital expenditures, particularly at CL&P, due to the completion in 2008 of three major transmission projects in southwest Connecticut, offset by increases at PSNH and WMECO resulting from higher generation capital expenditures related to the PSNH Clean Air Project and higher transmission capital expenditures related to WMECO's expenditures for the NEEWS project (refer to "Business Development and Capital Expenditures" of this *Management's Discussion and Analysis* for further discussion).

As a result of Lehman Brothers Commercial Bank's (LBCB) refusal in 2008 to continue to fund its commitment of approximately $56 million under our credit facilities, our aggregate borrowing capacity under our credit facilities was reduced from $900 million to $844 million. This borrowing capacity, when combined with our access to other funding sources, provides us with adequate liquidity.

NU parent s credit facility, in a nominal aggregate amount of $500 million, $482.3 million excluding the commitment of LBCB, expires on November 6, 2010. As of December 31, 2009, NU parent had $41 million of LOCs issued for the benefit of certain subsidiaries (primarily PSNH) and $100.3 million of borrowings outstanding under this facility. The weighted-average interest rate on these short-term borrowings as of December 31, 2009 was 0.63 percent, which is based on a variable rate plus an applicable margin based on NU parent's credit ratings. NU parent had approximately $341 million of borrowing availability on this facility as of December 31, 2009, excluding LBCB's commitment, as compared to $101.3 million of availability as of December 31, 2008.

The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million, $361.8 million excluding the commitment of LBCB, which also expires on November 6, 2010. There were no borrowings outstanding under this facility as of December 31, 2009, and the $361.8 million facility was available. The regulated companies had approximately $56.5 million of aggregate borrowing availability on this facility as of December 31, 2008, excluding LBCB's commitment and subject to each individual company's borrowing limits.

Our credit facilities and bond indentures require that NU parent and certain of its subsidiaries, including CL&P, PSNH and WMECO, comply with certain financial and non-financial covenants as are customarily included in such agreements, including maintaining a ratio of consolidated debt to total capitalization of no more than 65 percent. All such companies 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 these agreements.

Impact of Financial Market Conditions: While the impact of continued market volatility and the extent and impacts of the declining economic environment cannot be predicted, we are confident that we currently have operating flexibility and access to funding sources to maintain adequate liquidity. The credit outlooks for NU parent and its regulated companies are all stable. Our companies have low risk of calls for collateral due to our business model, and we have no long-term debt maturing until April 2012. An estimated cash contribution to our pension plan of approximately $45 million is expected to be made in the third quarter of 2010, and we project capital expenditures for 2010 of approximately $1.1 billion. However, we project cash flows provided by operating activities for 2010 of approximately $700 million, net of RRB payments, and, based on our successful financings in 2009, we expect to be able to access the capital markets in 2010 for our total planned debt issuances of approximately $145 million.

While we expect to renew our credit facilities before their November 6, 2010 expiration dates, costs associated with the new facilities will likely be higher than those associated with the existing credit facilities due to changes in credit market conditions.

On October 7, 2009, the Internal Revenue Service issued final regulations on the Pension Protection Act (PPA) funding rules, which allows us to maximize our funding flexibility by using the October 2008 yield curve rate for the January 1, 2009 valuation of pension plan liabilities. Using the October 2008 yield curve rate, our pension plan funded ratio (the value of plan assets divided by the funding target in accordance with the requirement of the PPA) was 100 percent as of January 1, 2009. As of January 1, 2010, the fair value of our pension plan assets increased by $232.8 million to $1.79 billion, and our estimated pension plan funded ratio was 90 percent. We currently estimate that a contribution of approximately $45 million will be made in the third quarter of 2010 for the purpose of satisfying benefit obligations accrued during 2009. We will potentially make contributions totaling approximately $200 million in 2011. The actual amounts of contributions in 2011 and in future plan years will depend on many factors, including the performance of existing plan assets, valuation of the plan's liabilities, and long-term discount rates.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portions of pension and PBOP expense or income (all of which are non-cash factors), totaled $969.2 million in 2009, compared with $1.3 billion in both 2008 and 2007. These amounts included $52.7 million in 2009, $33.2 million in 2008, and $16 million in 2007 that related to our corporate service companies that support the regulated companies.

Regulated Companies: Capital expenditures for the regulated companies totaled $916.5 million ($446 million for CL&P) in 2009.

<u>Transmission Segment</u>: Transmission segment capital expenditures decreased by $422.5 million in 2009, as compared with 2008, due primarily to a $423.3 million reduction in expenditures at CL&P, which completed three major transmission projects in southwest Connecticut in the second half of 2008. A summary of transmission segment capital expenditures by company in 2009, 2008 and 2007 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2009**	**2008**	**2007**
CL&P	$ 163.0	$ 586.3	$ 660.6
PSNH	61.1	81.9	80.7
WMECO	67.7	46.1 *	20.5 *
Totals	$ 291.8	$ 714.3	$ 761.8

*

Includes $1.9 million in 2008 and $1.2 million in 2007 of capital additions of HWP Company (HWP), formerly known as Holyoke Water Power Company, which were transferred to WMECO in December 2008.

In October 2008, CL&P and WMECO made state siting filings in Connecticut and Massachusetts, respectively, for the first and largest component of our New England East-West Solutions (NEEWS) project, the Greater Springfield Reliability Project (GSRP). In October 2009, the New England Independent System Operator (ISO-NE) affirmed the need and need date for GSRP. In Connecticut, hearings have been completed and final briefs were filed in mid-January 2010 with the Connecticut Siting Council (CSC). We believe a final decision may be received from the CSC as early as March 2010. In Massachusetts, hearings were completed in mid-February 2010 with final briefs expected to be filed in the spring. We expect to receive a final decision from the Energy Facilities Siting Board in the third quarter of 2010. GSRP, which involves the construction of a 115 kilovolt (KV)/345 KV line from Ludlow, Massachusetts to Bloomfield, Connecticut, is the largest and most complicated project within NEEWS and is expected to cost approximately $714 million if built according to our preferred route configuration. Following decisions from the state siting boards, we expect to commence construction in late 2010 and to 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 estimate CL&P's share of the costs of this project will be approximately $250 million. Municipal consultations concluded in November 2008, and CL&P plans to file its siting application with Connecticut regulators later in 2010, following the completion of ISO-NE s reassessment of the need date and issuance of its regional system plan. We currently expect the project to be placed in service in 2014.

The third major 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 Interstate Reliability Project. This project is currently expected to cost approximately $315 million.

ISO-NE is currently performing an evaluation of all projects in its regional system plan, including the other components of NEEWS, and assessing the presently estimated need dates for these projects. We expect ISO-NE s view on need dates for the second and third major NEEWS projects to be updated in the next version of the regional system plan, which we expect to see as a draft during the third quarter of 2010.

Included as part of NEEWS are approximately $211 million of associated reliability related expenditures for projects, over $50 million of which are moving forward through the siting and construction phases and are expected to be completed in advance of the three major projects. We estimate that CL&P's and WMECO's total capital expenditures for NEEWS will be $1.49 billion. Our current capital expenditure and rate base forecasts assume that all NEEWS projects are completed by the end of 2014. However, the timing and amount of our projected annual capital spending could be affected if receipt of siting approvals is delayed or if the need dates for these projects change through ISO-NE's regional system planning process. During the siting approval process, state regulators may require

changes in configuration (including placing some lines underground) 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 of the project beyond those reflected above. Since inception of NEEWS through December 31, 2009, CL&P and WMECO have capitalized approximately $67.5 million and $74.3 million, respectively, in costs associated with NEEWS, of which $34.2 million and $40 million, respectively, were capitalized in 2009.

NU and NSTAR are jointly planning a new, participant-funded, HVDC transmission line from New Hampshire to Canada (HQ tie line project) where it will interconnect with a transmission line being planned by Hydro-Québec (HQ), a large Canadian utility. Under the proposed arrangement, NU and NSTAR would sell to HQ 1,200 MW of firm electric transmission service over the HQ tie line project in order for HQ to sell and deliver this same amount of firm electric power from Canadian low-carbon energy resources to New England. The FERC granted approval of the HQ tie line project structure on May 22, 2009.

We have made significant progress in the design of the HQ tie line project and reached conceptual agreement in the development of a Transmission Service Agreement (TSA) with HQ. There are several routing options still under technical review and we expect to resolve them by the end of the first half of 2010. We anticipate that we will be filing the TSA with the FERC, which will regulate the tariff charges under the TSA, and the project design with ISO-NE for technical review by mid-2010. In addition, there are a number of state and federal permits that will be required to site the HQ tie line project and we anticipate filing those applications in 2010 as well. Though contingent on timely siting approvals, we currently expect to begin construction of the line in 2012 and have power flowing in 2015 (which coincides with HQ s planned completion of several new hydro-electric facilities). We estimate NU's share of this project to be $675 million.

In addition, we have started to negotiate a long term power purchase agreement with HQ for power flows over the HQ tie line project. Our intention is to create a power purchase agreement structure that could be offered to other load serving entities in addition to NU and NSTAR. Power purchase agreement terms will be subject to state regulatory approvals and critical to winning state policy maker support for the HQ tie line project. We anticipate these agreements to be filed in 2010 as well.

Distribution Segment: Distribution segment capital expenditures increased by $73.6 million in 2009, as compared with 2008, due primarily to increased generation business capital expenditures at PSNH related to its Clean Air Project and the absence in 2009 of a $17.5 million capital cost recovery by Yankee Gas related to a legal settlement in February 2008. A summary of distribution segment capital expenditures by company for 2009, 2008 and 2007 is as follows:

For the Years Ended December 31,

(Millions of Dollars)	2009	2008	2007
CL&P	$ 283.0	$ 296.6	$ 283.3
PSNH	98.8	98.2	88.3
WMECO	37.7	37.8	34.0
Totals - electric distribution (excluding generation)	419.5	432.6	405.6
Yankee Gas	59.6	44.0	63.7
Other	0.6	0.5	0.4
Total distribution	479.7	477.1	469.7
PSNH generation	145.0	74.0	35.3
Total distribution segment	$ 624.7	$ 551.1	$ 505.0

PSNH's Clean Air Project is a $457 million wet scrubber project at its Merrimack coal station, the cost of which will be recovered through PSNH's default energy service (ES) rates under New Hampshire law. Construction is expected to be under budget and completed in mid-2012. Since inception of the project, PSNH has capitalized approximately $146.8 million associated with this project, of which $119.3 million was capitalized in 2009. Construction of the project was approximately 34 percent complete as of December 31, 2009.

On January 6, 2010, the DPUC issued a decision approving Yankee Gas' request to sell its four remaining propane plants that were used to supply gas during peak periods. As a result, in order to meet future supply needs during peak periods, Yankee Gas has initiated a project to construct 16 miles of main gas pipeline between Waterbury, Connecticut and Wallingford, Connecticut and an expansion of the Yankee Gas liquefied natural gas (LNG) plant's vaporization output (collectively, the WWL project), which are estimated to cost $67 million. The WWL Project will connect the LNG storage facility, which is located in Waterbury, Connecticut and is capable of storing the equivalent of 1.2 bcf of natural gas, to areas with growing demand. This project is scheduled to begin construction in the second quarter of 2010 and completed by late 2011. In 2009, Yankee Gas capitalized $0.8 million associated with this project.

Strategic Initiatives: We continue to evaluate certain development projects, some of which would benefit our customers, such as investments in AMI systems and other projects that are detailed below:

Over the past two years, we have participated in discussions with other utilities, policymakers, and prospective developers of renewable energy projects in the New England region regarding a framework whereby renewable power projects built in rural areas of northern New England could be connected to the electric load centers of New England. We believe there are significant opportunities for developers to build wind and biomass projects in northern New England that could help the region meet its renewable portfolio standards. We believe that a collaborative approach among project developers and transmission owners is necessary to be able to construct needed projects and bring their electrical output into the market. To date, most discussions have been conceptual in nature and therefore we have not yet included any capital expenditures associated with potential projects in our five-year capital program.

On December 1, 2009, CL&P filed with the DPUC the results of a three-month dynamic pricing smart meter pilot program that involved nearly 3,000 customers (1,500 residential and 1,500 commercial and industrial (C&I) customers). CL&P plans to file a smart metering and dynamic pricing plan with the DPUC by March 31, 2010. The total cost of the pilot program was approximately $13 million and is being recovered through CL&P FMCC rates.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. The program proposes to involve 1,750 customers in WMECO's service region for a term of six months beginning in April 2011. The total cost of the project is estimated to be $7 million, which would be recovered through rates WMECO would charge to customers. A decision is expected from the DPU in the first half of 2010.

On August 12, 2009, the DPU approved a stipulation agreement between WMECO and the AG concerning WMECO's proposal, under the Massachusetts Green Communities Act (GCA), to install 6 MW of solar energy generation in its service territory at an estimated cost of $41 million. Under the agreement, no more than 3 MW will be commissioned in any one year between 2010 and 2012, the ROE on these assets will be a fully tracking 9 percent, and the benefits of renewable energy and tax credits will be used to reduce the impact on customer bills. WMECO will need to file an additional application with the DPU if it seeks to develop more than the initial 6 MW under the GCA, which allows for electric utility ownership of up to 50 MW of solar energy generating facilities.

The estimated capital expenditures discussed below include expenditures for the WMECO solar program.

Projected Capital Expenditures and Rate Base Estimates: A summary of the projected capital expenditures for the regulated companies' transmission and the distribution and generation businesses, by company, for 2010 through 2014, including our corporate service companies' capital expenditures on behalf of the regulated companies, is as follows:

	Year					
(Millions of Dollars)	**2010**	**2011**	**2012**	**2013**	**2014**	**2010-2014 Totals**
CL&P transmission	$ 136	$ 203	$ 281	$ 286	$ 155	$ 1,061
PSNH transmission	55	118	107	74	22	376
WMECO transmission	66	256	328	156	6	812
HQ tie line project	16	49	90	236	282	673
Subtotal transmission	$ 273	$ 626	$ 806	$ 752	$ 465	$ 2,922
CL&P distribution	305	313	306	305	317	1,546
PSNH distribution	113	111	115	121	134	594

WMECO distribution	33	39	36	35	36	179
Subtotal electric distribution	$ 451	$ 463	$ 457	$ 461	$ 487	$ 2,319
PSNH generation	187	117	82	68	26	480
WMECO generation	20	14	7	-	-	41
Subtotal generation	$ 207	$ 131	$ 89	$ 68	$ 26	$ 521
Yankee Gas distribution	112	104	80	82	83	461
Corporate service companies	48	25	22	25	14	134
Totals	$ 1,091	$ 1,349	$ 1,454	$ 1,388	$ 1,075	$ 6,357

Actual capital expenditures could vary from the projected amounts for the companies and periods above. The continuation of weak economic conditions in the Northeast could impact the timing of our major transmission projects. Most of these capital investment projections, including those for the HQ tie line project, assume timely regulatory approval, which in some cases requires extensive review. Delays in or denials of those approvals could reduce the levels of expenditures, associated rate base, and anticipated EPS growth.

Based on the 2009 actual and 2010 through 2014 projected capital expenditures, the 2009 actual and 2010 through 2014 projected transmission, distribution, and generation rate base as of December 31 of each year are as follows:

	As of December 31,					
(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
CL&P transmission	$ 2,099	$ 2,105	$ 2,134	$ 2,318	$ 2,545	$ 2,563
PSNH transmission	315	335	433	530	608	584
WMECO transmission	183	240	429	665	889	851
HQ tie line project	-	-	-	-	-	675
Subtotal transmission	$ 2,597	$ 2,680	$ 2,996	$ 3,513	$ 4,042	$ 4,673
CL&P distribution	2,119	2,333	2,497	2,629	2,778	2,911
PSNH distribution	772	849	941	1,030	1,090	1,156
WMECO distribution	412	413	434	447	456	461
Subtotal electric distribution	$ 3,303	$ 3,595	$ 3,872	$ 4,106	$ 4,324	$ 4,528
PSNH generation	407	404	414	848	874	857
WMECO generation	-	-	29	31	28	25
Subtotal generation	$ 407	$ 404	$ 443	$ 879	$ 902	$ 882
Yankee Gas distribution	691	764	843	892	932	974
Totals	$ 6,998	$ 7,443	$ 8,154	$ 9,390	$ 10,200	$ 11,057

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 (RTO) for New England since February 1, 2005. ISO-NE works to ensure the reliability of the New England transmission system, administers the independent system operator tariff, 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: NU's transmission rates recover total transmission revenue requirements, ensuring that we recover all regional and local revenue requirements. These 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. As of December 31, 2009, NU was in a total underrecovery position of $38.8 million ($28.2 million for CL&P) that will be collected from customers in June 2010.

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 the 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 addition, while not an issue in this rehearing, the initial order increasing the ROE by 50 additional basis points for transmission owners joining a RTO and giving the RTO operational control of the transmission facilities still stands. This order was appealed to the D.C. Circuit Court of Appeals by numerous state regulators and consumer advocates. On January 29, 2010, the Court unanimously rejected the claims on appeal, confirming FERC s award of the 100 basis point adder. It is not known at this time if appellants will seek further review from the U.S. Supreme Court.

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 the FERC s guidelines for new projects, and requested an additional 50 basis point adder for advanced technology used in the project.

In July 2008, the FERC granted the waiver request and approved the 100 basis point ROE 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. 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. Connecticut state regulators have taken an appeal to the D.C. Circuit Court of Appeals. A schedule for the appeal has not yet been set.

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

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An ROE of 12.89 percent, representing an incentive of 125 basis points;

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100 percent inclusion of prudently incurred construction work in progress (CWIP) in rate base; and

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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 has not yet been acted on by the FERC.

Legislative Matters

2009 Federal Legislation: The American Recovery and Reinvestment Act of 2009 provides resources through grants and loans for several energy-related areas that are relevant to NU, including funding for energy efficiency, smart grid, renewable energy and transmission projects. This legislation also extended tax rules allowing the accelerated deduction of depreciation, which had a positive impact to our 2009 operating cash flows of approximately $100 million.

Climate Change and Greenhouse Gas Issues: Global climate change and greenhouse gas emission issues have received an increased focus from state governments and the federal government, particularly in the last year. The U.S. Environmental Protection Agency (EPA) has initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" and endanger public health and welfare and should be regulated. The largest source of greenhouse gas emissions in the U.S. is the electricity generating sector.

Climate change concerns and greenhouse gas issues could lead to additional rules and regulations that impact how we operate our business, both in terms of the generating facilities we own and operate as well as general utility operations. These could include federal cap and trade laws, or regulations requiring additional capital expenditures at our generating facilities. Any such regulations or laws will likely impact PSNH's generating plants and possibly the prices that CL&P and WMECO pay for generation service. In addition, such legislation could potentially impact the prices we pay for goods and services provided by companies directly affected by such legislation. We would expect that any costs of these rules and regulations would be recovered from customers, but such costs could impact energy use by our customers. To date, the regulatory consequences of global climate change have not materially affected us, and it is uncertain what effects, if any, this issue will have on us in the future. For further information see Other Regulatory and Environmental Matters - Climate Change and Greenhouse Gas Issues in Item 1, *Business*.

2009 Massachusetts Legislation: In November 2009, in response to a severe winter storm in December 2008, Massachusetts passed legislation that authorizes the DPU to levy financial penalties if utilities do not follow approved storm plans and puts into law existing requirements for utility storm restoration plans. The new law provides that under a declared state of emergency, the Governor may authorize the DPU Chairman to issue extraordinary temporary orders on utilities to expend funds and redeploy resources to restore service with failure to carry out such an order subject to investigation and a penalty of up to $1 million per violation. The law also codifies existing requirements for utilities to file storm restoration plans and creates significant new financial penalties for late filing and for any failure to implement such plans and requires each utility to submit annual emergency response plans for DPU review and approval. There is no current impact on WMECO s financial condition from this legislation.

Regulatory Developments and Rate Matters

Connecticut - CL&P:

Distribution Rates: CL&P implemented new distribution rates in 2009 to reflect the DPUC's 2008 decision allowing a $20.1 million annualized increase in distribution rates, effective February 1, 2009. On January 8, 2010, CL&P filed an application with the DPUC to raise distribution rates by $133.4 million, or 3.4 percent over current revenues, to be effective July 1, 2010, and by an additional $44.2 million, or 1.1 percent over current revenues, to be effective July 1, 2011. Among other items, CL&P is seeking an increase in its authorized ROE from the current 9.4 percent to 10.5 percent. CL&P proposed that the first year s increase be deferred until January 1, 2011 and that approximately $67 million of cash revenue requirement for the second half of 2010 would be deferred and recovered from CL&P customers between January 1, 2011 and June 30, 2012. If approved by the DPUC, the application would require an annualized $210 million increase in distribution rates to take effect on January 1, 2011. CL&P expects that as a result of a decline in stranded cost recoveries due to the final amortization of CL&P s rate reduction bonds in December 2010, CL&P s Competitive Transition Assessment (CTA) will decline by approximately $230 million on an annualized basis on January 1, 2011, more than offsetting the impact of the distribution rate increase. Hearings before the DPUC are scheduled to begin in March 2010 and a decision is expected in mid-2010.

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. Effective April 1, 2009, the DPUC approved a decrease to CL&P s total average LRS rate of approximately 22 percent. Effective July 1, 2009, the DPUC approved total average SS rates that did not change from the previous rates, though the energy supply portion of the rates increased from 12.316 cents per kilowatt-hour (KWh) to 12.516 cents per KWh. The DPUC also approved a decrease to CL&P's total average LRS rates of approximately 2.3 percent, which was primarily the result of the energy supply portion decreasing to 7.944 cents per KWh. Effective October 1, 2009, the DPUC approved an increase to CL&P's total average LRS rates of approximately 5.8 percent, which was primarily the result of the energy supply portion increasing to 8.657 cents per KWh. Effective January 1, 2010, the DPUC approved a decrease to CL&P s total average SS rates of approximately 4.6 percent and an increase in the total average LRS rate of approximately 10.2 percent. The energy supply portion of the total average SS rate decreased from 12.516 cents per KWh to 11.289 cents per KWh. The energy supply portion of the total average LRS rate increased from 8.657 cents per KWh to 9.662 cents per KWh. CL&P is fully recovering from customers the costs of its SS and LRS services.

CTA and SBC Reconciliation: On March 31, 2009, CL&P filed with the DPUC its 2008 CTA and Systems Benefits Charge (SBC) reconciliation, which compared CTA and SBC revenues charged to customers to revenue requirements, which allow for full recovery of these amounts. For the 12 months ended December 31, 2008, total CTA revenues exceeded CTA revenue requirements by $84.9 million, which was recorded as a decrease to Regulatory assets on the accompanying consolidated balance sheets. For the 12 months ended December 31, 2008, the SBC revenues exceeded SBC revenue requirements by $2.5 million, which was recorded as a decrease to Regulatory assets on the accompanying consolidated balance sheets. On September 30, 2009, the DPUC issued a final decision in this docket that approved the 2008 CTA and SBC reconciliations as filed and provided for a subsequent review that resulted in the DPUC increasing the CTA rate by approximately 0.1 cent per KWh, effective January 1, 2010.

FMCC Filing: On February 6, 2009, CL&P filed with the DPUC its semi-annual FMCC filing, which reconciled actual FMCC revenues and charges and GSC revenues and expenses, for the period July 1, 2008 through December 31, 2008, and also included the previously filed revenues and expenses for the January 1, 2008 through June 30, 2008 period. The filing identified an underrecovery for the full year totaling approximately $31.9 million. On November 25, 2009, the DPUC issued a final decision accepting CL&P's calculations as filed. On August 3, 2009, CL&P filed with the DPUC its semi-annual FMCC filing for the period January 1, 2009 through June 30, 2009, which identified a net underrecovery of $7.1 million for that period. On December 16, 2009, the DPUC issued a final decision on this filing accepting CL&P s calculations as filed. On February 5, 2010, CL&P filed with the DPUC its semi-annual filing, which reconciled actual FMCC revenues and charges and GSC revenues and expenses, for the period July 1, 2009 through December 31, 2009, and also included the previously filed revenues and expenses for the January 1, 2009 through June 30, 2009 period. The filing identified a total net underrecovery of $6.5 million, which includes the remaining uncollected portions of previous filings' underrecoveries and has been recorded as a Regulatory asset on the accompanying consolidated balance sheets. We do not expect the outcome of the DPUC's review of this filing to have a material adverse impact on CL&P's earnings, financial position or cash flows.

Renewable Energy Contracts: In May 2009, pursuant to Connecticut s "Act Concerning Energy Independence," the DPUC approved five renewable energy plant projects with total capacity of 27.3 MW. Contracts for the purchase of energy, capacity and renewable energy certificates from these projects have been signed by CL&P and were approved by the DPUC on August 4, 2009. Purchases under the contracts are scheduled to begin from September 2010 through July 2011 and to extend for 15 to 20 years. As directed by the DPUC, CL&P and The United Illuminating Company (UI) have 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. CL&P s portion of the costs and benefits of these contracts will be paid by or refunded to CL&P s customers.

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 for the years 2004, 2005 and 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 was established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009. On February, 4, 2010, the Connecticut Superior Court reversed the DPUC decision. The Court remanded the case back to the DPUC for the correction of several specific errors. We do not yet know if the DPUC will appeal the Court's finding or what the schedule of the remanded case will be.

New Hampshire:

Merrimack Clean Air Project: On July 7, 2009, the New Hampshire Site Evaluation Committee voted that PSNH s Clean Air Project to install wet scrubber technology at its Merrimack Station was not subject to the Committee s review as a "sizeable" addition to a power plant under state law. That Committee upheld its decision in an order dated January 15, 2010, denying requests for rehearing. This order was appealed on February 23, 2010; however, we do not believe that the appeal will have a material impact on the timing or costs of the project. On August 5, 2009, the New Hampshire Supreme Court dismissed an appeal of a prior NHPUC ruling on the project, holding the appellants were not harmed and thus lacked standing to bring their challenge. PSNH continues to develop this project, which has a total estimated cost of $457 million and for which construction is approximately 34 percent complete as of December 31, 2009.

Distribution Rates: The NHPUC issued an order on July 31, 2009 approving a temporary increase of $25.6 million in PSNH s distribution rates on an annualized basis, effective August 1, 2009. Included in the $25.6 million temporary increase is $6 million to begin the recovery of PSNH's approximately $49 million deferral of storm costs incurred in December 2008.

On June 30, 2009, PSNH filed an application with the NHPUC requesting a permanent increase in distribution rates of approximately $51 million on an annualized basis to be effective August 1, 2009, and another $17 million to be effective July 1, 2010. Hearings before the NHPUC are scheduled for April 2010 and PSNH expects a decision in mid-2010. Any differences between allowed temporary rates and permanent rates will be reconciled back to August 1, 2009.

ES and SCRC Rates: On July 23, 2009 and July 24, 2009, the NHPUC approved stranded cost recovery charge (SCRC) and ES rates of 1.14 cents and 9.03 cents per KWh, respectively, which were effective August 1, 2009 through December 31, 2009. On December 22, 2009 and December 31, 2009, the NHPUC approved SCRC and ES rates of 1.18 cents and 8.96 cents per KWh, respectively, which are effective January 1, 2010 through December 31, 2010.

TCAM Rates: On July 24, 2009, the NHPUC approved a transmission cost adjustment mechanism (TCAM) rate of 1.195 cents per KWh, which is effective August 1, 2009 through June 30, 2010.

ES and SCRC Reconciliation: On an annual basis, PSNH files with the NHPUC an ES/SCRC reconciliation filing for the preceding year. On May 1, 2009, PSNH filed its 2008 ES/SCRC reconciliation with the NHPUC, whose evaluation includes a prudence review of PSNH's generation activities. During 2008, ES revenues exceeded ES costs by $20.7 million, and SCRC costs exceeded SCRC revenues by $6.4 million, resulting in an ES regulatory liability for refunds to customers and a SCRC regulatory asset for costs that will be recovered from customers. PSNH includes these deferrals in the subsequent ES/SCRC rate calculation as a means of refunding/recovering these amounts to/from customers in the next ES/SCRC rate period. On December 30, 2009, the NHPUC approved a settlement on the reconciliation filing that did not have a material adverse impact on PSNH s earnings, financial position or cash flows.

Massachusetts:

Customer Rates: On December 30, 2009, the DPU approved rate changes for WMECO's various tracking mechanisms effective January 1, 2010. On an aggregate basis, these changes resulted in an increase in customer rates of 0.509 cents per KWh, or 3.7 percent. WMECO intends to file a distribution rate case in mid-2010 to be effective January 1, 2011. The distribution rate case will include a proposal, as required by the DPU, to fully decouple distribution revenues from KWh sales.

Basic Service Rates: In 2009, basic service rates ranged from 8.554 cents per KWh to 11.805 cents per KWh for residential customers, 9.179 cents per KWh to 12.074 cents per KWh for small commercial and industrial customers, and 7.256 cents per KWh to 10.212 cents per KWh for medium and large commercial and industrial customers. Effective January 1, 2010, the rates for all basic service customers changed to reflect the basic service solicitations conducted by WMECO in November 2009. Basic service rates for residential customers decreased to 8.257 cents per KWh, rates for small commercial and industrial customers decreased to 8.992 cents per KWh and rates for medium and large commercial and industrial customers increased to 8.913 cents per KWh.

Transition Cost Reconciliations: On June 2, 2009, the DPU issued a decision on WMECO s 2007 transition cost reconciliation, which did not have a material adverse impact on WMECO s earnings, financial position or cash flows. On July 2, 2009, WMECO filed its 2008 cost reconciliation for transition, transmission, basic/default service, basic/default service adder, and capital projects scheduling list. The briefing period ended on December 28, 2009. The DPU is expected to issue a decision in 2010. We do not expect the outcome of the DPU's review of this filing to have a material adverse impact on WMECO's earnings, financial position or cash flows.

Pension Factor Reconciliation Filing: On July 2, 2009, WMECO filed the 2008 reconciliation for its pension factor revenues and expenses. There is currently no timeline for the DPU's review of this filing. We do not expect the outcome of the DPU's review of this filing to have a material adverse impact on WMECO's earnings, financial position or cash flows.

Service Quality Performance Assessment: WMECO is subject to service quality (SQ) metrics that measure safety, reliability and customer service. Any charges incurred for failure to meet these standards are paid by WMECO to customers through a method approved by the DPU. WMECO will likely be required to pay assessment charges for its 2008 and 2009 reliability performance against the metrics established for those years, primarily as a result of significant storm activity in 2008 and a power outage impacting WMECO s Springfield underground service territory in 2009. WMECO has performed at target for certain other non-storm related reliability metrics. WMECO filed its 2008 SQ results and assessment calculation with the DPU in March 2009 and will file its 2009 information with the DPU in March 2010. In 2009 and 2008, WMECO recorded estimated pre-tax charges of $0.7 million and $1.3 million, respectively, to Net income for these assessments.

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. Our percentage share of the obligation to support the Yankee companies under FERC-approved rate tariffs is the same as our ownership percentage. For further information, see Note 1K, "Summary of Significant Accounting Policies Equity Method Investments," to the consolidated financial statements.

The Yankee Companies 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 already 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 each filed subsequent 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 to manage its electrical contracting business.

Wholesale Marketing: During 2009, Select Energy continued to manage its long-term wholesale energy sales contract with the New York Municipal Power Agency (NYMPA), an agency comprised of municipalities, that expires in 2013, and related energy supply contracts. In addition to the NYMPA portfolio, Select Energy has a contract to operate and purchase the output of a generating facility in New England through mid-2012.

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 other than E.S. Boulos Company (Boulos), an electrical contractor based in Maine that we continue to own and manage.

NU Enterprises Contracts

Wholesale Energy Contracts: NU Enterprises' wholesale energy contracts (managed through its subsidiary Select Energy), which are accounted for as derivatives, are subject to mark-to-market accounting. Numerous factors could either positively or negatively affect the realization of the net fair value amounts of these energy contracts to cash. These factors include: 1) volatility of commodity prices until the derivative contracts result in deliveries, are exited or expire; 2) differences between expected and actual volumes; 3) the performance of counterparties; and 4) other factors.

Select Energy has policies and procedures requiring all of its wholesale 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 energy contracts are identified and segregated in the table of fair value of wholesale derivative contracts as of December 31, 2009 and 2008. 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 intra-month price volatility and exit pricing assumptions. Currently, a portion of the NYMPA contract's fair value related to intra-month volatility and an exit price premium are determined based upon a model.

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 energy 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 accounting guidance for fair value measurements, 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, all of these contracts are classified as Level 3 under this guidance. As of December 31, 2009 and 2008, the sources of the fair value of wholesale energy derivative contracts are included in the following tables:

(Millions of Dollars)	**Fair Value of Wholesale Contracts as of December 31, 2009**							
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	$	(5.5)	$	(18.8)	$	-	$	(24.3)
Prices provided by external sources		(3.3)		(8.1)		-		(11.4)
Model-based		(2.0)		(7.5)		-		(9.5)
Totals [(1)]	$	(10.8)	$	(34.4)	$	-	$	(45.2)

(Millions of Dollars)	Fair Value of Wholesale Contracts as of 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	(1.7)	(6.7)	(3.0)	(11.4)
Totals	$ (14.5)	$ (35.2)	$ (14.2)	$ (63.9)

(1)

Excludes $2.1 million of cash collateral posted under master netting agreements.

For the years ended December 31, 2009 and 2008, the changes in fair value of these contracts are included in the following table:

	Total Portfolio Fair Value	
	2009	**2008**
(Millions of Dollars)		
Fair value of wholesale contracts outstanding at the beginning of the year	$ (63.9)	$ (94.0)
Pre-tax effects of implementing fair value measurement accounting guidance ($3.2 million after-tax) [1]	-	(6.1)
Contracts realized or otherwise settled during the year [2]	12.4	29.2
Change in unrealized gains included in pre-tax earnings	6.3	7.0
Fair value of wholesale contracts outstanding at the end of the year	$ (45.2)	$ (63.9)

(1)

Pre-tax effect recorded in Fuel, purchased and net interchange power on the accompanying consolidated statements of income.

(2)

Amount includes purchases, issuances and settlements of $12.5 million and $24.2 million for the years ended December 31, 2009 and 2008, respectively, and net realized intra-month (losses)/gains of $(0.1) million and $5 million for the years ended December 31, 2009 and 2008, respectively.

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 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. As of December 31, 2009, approximately 98 percent of Select Energy's counterparty credit exposure to wholesale counterparties was non-rated, and approximately 2 percent was collateralized. All 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: NU parent provides standby LOCs for the benefit of its subsidiaries under its revolving credit agreement. PSNH posts such LOCs as collateral with counterparties and ISO-NE. As of December 31, 2009, PSNH had posted $39 million in such NU parent LOCs, which includes $10 million with ISO-NE. In addition, Select Energy had posted a $2 million NU parent LOC with ISO-NE as of December 31, 2009.

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 7E, "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 and manage every risk or event that could impact our financial condition, results of operations or cash flows. 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, results of operations or cash flows. 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 discussions of these policies and estimates as well as other accounting policies, estimates and assumptions used in the preparation of our consolidated financial statements.

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.

The application of accounting guidance applicable to rate-regulated enterprises 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 the accounting guidance applicable to rate-regulated enterprises to our operations, or if we could not conclude that it is probable that costs would be recovered or reflected in future rates, the costs would be charged to earnings in the period in which they were incurred. If we determine that a regulatory asset is no longer probable of recovery in rates, then we would record the charge in earnings at that time.

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

Unbilled Revenues: The determination of retail energy sales to residential, commercial and industrial 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 majority 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 recorded.

Unbilled revenues represent an estimate of electricity or gas delivered to customers but not yet billed. Unbilled revenues are included in Operating revenues 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 2009.

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 and 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.

Wholesale transmission revenues are based on formula rates that are approved by the FERC. These rates are based on forecasted transmission formulas, primarily derived from historical financial results and estimates of forecasted plant in service, which are subject to annual true-ups in the subsequent year. There can be differences in estimated versus actual transmission rates and revenues depending upon a variety of factors, including transmission plant placed in service earlier or later than expected and FERC orders that change the authorized ROEs.

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

Pension and PBOP: Our subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all of 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, results of operations or cash flows.

Pre-tax periodic pension expense for the Pension Plan was $39.7 million, $2.4 million and $17.4 million for the years ended December 31, 2009, 2008 and 2007, respectively, excluding a one-time termination benefit of $0.3 million in 2007. The pre-tax net PBOP Plan expense was $37.2 million, $36.2 million and $38.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Long-Term Rate of Return Assumptions and Plan Assets: 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 historical returns. Our expected long-term rates of return on assets are based on certain target asset allocation assumptions and corresponding assumed rates of returns. We used 8.75 percent for 2009 for the aggregate long-term rate of return on Pension Plan and PBOP Plan life and non-taxable health assets and 6.85 percent for PBOP taxable health assets. We will continue to evaluate these actuarial assumptions at least annually and will adjust them as necessary. We routinely review the actual asset allocations and periodically rebalance the investments to the targeted asset allocations when appropriate. For information regarding actual asset values, see Note 5A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements.

Investment securities are exposed to various risks, including interest rate, credit and market price volatility. As a result of these risks, the market values of investment securities could increase or decrease in the near term, resulting in a material impact on the value of our plan assets. Increases or decreases in market values could materially affect the future level of pension and other postretirement benefit expense.

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 in plan assets 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 of December 31, 2009, total investment losses to be reflected in the four-year rolling average of plan assets over the next four years were $350.4 million and $30.9 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 or losses. The Plans currently amortize unrecognized gains or losses as a component of pension and PBOP expense over the average future employee service period of approximately 12 years.

As of December 31, 2009, the net actuarial losses on the Pension and PBOP Plan liabilities, also subject to amortization over the next 12 years, were $570 million and $154 million, respectively.

Discount Rate: Cash flows related to the Pension Plan or PBOP Plan liability stream are discounted at interest rates applicable to the timing of the cash flow. The discount rate that is utilized in determining future pension and PBOP obligations is based on a yield-curve approach. The yield curve is developed from the top quartile of "AA-rated" Moody s and S&P s bonds without callable features outstanding as of December 31, 2009. 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 5.98 percent for the Pension Plan and 5.73 percent for the PBOP Plan as of December 31, 2009. Discount rates used as of December 31, 2008 were 6.89 percent for the Pension Plan and 6.90 percent for the PBOP Plan.

Forecasted Expenses and Expected Contributions: Due to the effect of the unrecognized actuarial gains or losses and based on the long-term rate of return assumptions, discount rates and other assumptions, we estimate that forecasted expense for the Pension Plan and PBOP Plan will be $79.5 million and $41.2 million, respectively, in 2010, which is included in our earnings 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 our policy to contribute to the PBOP Plan at the amount of PBOP expense, excluding curtailments and special benefit amounts and adding contributions for the amounts received from the federal Medicare subsidy.

We have not been required to make a contribution to the Pension Plan since 1991. As of January 1, 2010 and 2009, the fair value of our Pension Plan assets decreased from prior years due primarily to negative financial market conditions. On October 7, 2009, the Internal Revenue Service issued final regulations on the PPA funding rules, which allows us to maximize our funding flexibility by using the October 2008 yield curve rate for the January 1, 2009 valuation of Pension Plan liabilities. Using the October 2008 yield curve rate, our Pension Plan funded ratio (the value of plan assets divided by the funding target in accordance with the requirement of the PPA) was 100 percent as of January 1, 2009. We currently estimate that a contribution of approximately $45 million will be made in the third quarter of 2010 for the purpose of satisfying benefit obligations accrued during 2009, and that contributions totaling approximately $200 million could potentially be made in 2011 (using 24 month segment rates to determine the funding target beginning in 2010). The actual amounts of contributions in 2011 and in future plan years will depend on many factors, including the performance of existing plan assets, valuation of plan liabilities, and long-term discount rates.

Sensitivity Analysis: The following represents the increase 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):

	As of December 31,			
	Pension Plan Cost		Postretirement Plan Cost	
Assumption Change	**2009**	**2008**	**2009**	**2008**
Lower long-term rate of return	$ 11.1	$ 11.8	$ 1.7	$ 1.3
Lower discount rate	$ 12.0	$ 11.6	$ 1.5	$ 1.4
Higher compensation increase	$ 6.0	$ 6.2	N/A	N/A

Health Care Cost: The health care cost trend assumption used to project increases in medical costs was 8 percent for 2009, 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 PBOP Plan expense by $0.9 million in 2009. The effect of increasing the health care cost trend rate by one percentage point would have been a $12.9 million impact on the postretirement benefit obligation in 2009.

Goodwill and Intangible Assets: We are required to test goodwill balances 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 has determined that no triggering events occurred in 2009 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, 2009 for the Yankee Gas goodwill balance of $287.6 million. We determined that the fair value of Yankee Gas substantially exceeds its carrying value and no impairment exists. In performing the required impairment evaluation, we estimated the fair value of the Yankee Gas reporting unit and compared it to the carrying amount of the reporting unit, including goodwill. We estimated the fair value of Yankee Gas using discounted cash flow methodologies and an analysis of comparable companies or transactions. This analysis requires the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, and long-term earnings and merger multiples of comparable companies.

We determined the discount rate using the capital asset pricing model methodology. This methodology uses a weighted average cost of capital in which the ROE is calculated using risk-free rates, stock premiums and a beta representing Yankee Gas' volatility relative to the overall market. The resulting discount rate is intended to be comparable to a rate that would be applied by a market participant. The discount rate fluctuates from year to year as it is based on external market conditions. In 2009, the discount rate increased because the beta was higher in 2009 than 2008.

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 and the impact of temporary differences resulting from differing treatment of items. Such differences are the result of timing of the deduction for expenses, as well as any impact of permanent differences resulting from tax credits, non-tax deductible expenses, in addition to various other items, including items that directly impact our tax return as a result of a regulatory activity (flow-through items). 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. We record income tax expense quarterly using an estimated annualized effective tax rate. Adjustments to these estimates can significantly impact our consolidated financial statements.

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

We also account for uncertainty in income taxes, which 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. We follow generally accepted accounting principles to address the methodology to be used 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 this guidance 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 requires significant judgment and could change previous conclusions used to measure the tax position estimate. 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.

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 impact 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 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 and has spent approximately $16 million on this site. At this time, we believe that the $1.1 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $1.1 million to $1.8 million and will be sufficient for HWP to evaluate the results of additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation.

Fair Value Measurements: As of January 1, 2008, we adopted fair value measurement guidance that 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). As a result of implementing this guidance, we recorded a net after-tax reduction of 2008 earnings of $3.2 million related to Select Energy s remaining wholesale marketing contracts. 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. 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. As of December 31, 2009, we have applied the fair value measurement guidance to the Company's derivative contracts that are recorded at fair value, marketable securities held in NU s supplemental benefit trust and WMECO s spent nuclear fuel trust, our valuations of investments in our pension and PBOP plans, and nonrecurring fair value measurements of nonfinancial assets such as goodwill and AROs. See Note 1G, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 4, "Fair Value Measurements," to the accompanying consolidated financial statements for further information.

We use quoted market prices when available to determine fair values of financial instruments. 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. Derivative contracts are valued using models when quoted prices in active markets for the same or similar instruments are not available. These models 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 models 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, 2009, there were net unrealized gains of $3.8 million ($6.3 million pre-tax) related to the valuation of these contracts. Key drivers of variability in fair values include changes in energy prices and expected volumes under the contracts. We utilize judgment in estimating 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 the costs of these contracts 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 in determining fair value have a significant effect on derivative values.

Derivative assets are a large portion of our total assets measured at fair value (excluding assets held in our external pension and PBOP trusts), and derivative liabilities comprise almost all of our total liabilities measured at fair value as of December 31, 2009. A significant portion of our derivative liabilities relate to the regulated companies. Changes in fair value do not affect our earnings and 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.

We review and update our fair value hierarchy classifications on a quarterly basis. As of December 31, 2009, we held $64.3 million of investment securities in our supplemental benefit trust and $56.8 million of investment securities in our WMECO spent nuclear fuel trust. The fair values of these investments were determined using quoted market prices or other observable inputs.

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

Other Matters

Accounting Standards Issued But Not Yet Adopted and Accounting Standards Recently Adopted: For information regarding new accounting standards, see Note 1C, "Summary of Significant Accounting Policies - Accounting Standards Issued But Not Yet Adopted," and Note 1D, "Summary of Significant Accounting Policies - Accounting Standards Recently Adopted," to the consolidated financial statements.

Contractual Obligations and Commercial Commitments:

Information regarding our contractual obligations and commercial commitments as of December 31, 2009 is summarized annually through 2014 and thereafter as follows:

NU

(Millions of Dollars)	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Totals**
Long-term debt maturities (a) (b)	$ 66.3	$ 4.3	$ 267.3	$ 305.0	$ 275.0	$ 3,332.8	$ 4,250.7
Estimated interest payments on existing debt (c)	223.5	223.2	222.8	215.6	204.0	2,065.0	3,154.1
Capital leases (d)	2.5	2.5	2.6	2.4	2.0	13.4	25.4
Operating leases (e)	16.5	8.0	7.3	7.0	5.1	22.7	66.6
Funding of pension obligations (e)	45.0	200.0	N/A	N/A	N/A	N/A	245.0
Funding of other postretirement benefit obligations (e)	41.2	41.4	41.4	26.0	24.3	N/A	174.3
Estimated future annual regulated companies costs (f)	758.6	726.6	814.3	696.1	596.4	3,955.5	7,547.5
Estimated future annual NU Enterprises costs (f)	42.8	42.9	40.6	46.6	-	-	172.9
	1,576.9	-	-	-	-	-	1,576.9

Other purchase commitments [e] [h]							
Totals [g] [i]	$ 2,773.3	$ 1,248.9	$ 1,396.3	$ 1,298.7	$1,106.8	$ 9,389.4	$ 17,213.4

CL&P *(Millions of Dollars)*	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Totals**
Long-term debt maturities [a] [b]	$ 62.0	$ -	$ -	$ -	$ 150.0	$ 2,131.7	$ 2,343.7
Estimated interest payments on existing debt [c]	136.2	136.2	136.2	136.2	136.2	1,545.1	2,226.1
Capital leases [d]	1.9	1.9	2.0	2.0	1.8	13.2	22.8
Operating leases [e]	11.8	4.9	4.6	4.5	4.3	25.0	55.1
Funding of other postretirement benefit obligations [e]	16.9	16.9	16.8	9.3	8.7	N/A	68.6
Estimated future annual long-term contractual costs [f]	295.4	418.0	562.6	599.9	502.9	3,629.9	6,008.7
Other purchase commitments [e] [h]	729.2	-	-	-	-	-	729.2
Totals [g] [i]	$ 1,253.4	$ 577.9	$ 722.2	$ 751.9	$ 803.9	$ 7,344.9	$ 11,454.2

(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 $300.6 million and $243.5 million for NU and CL&P, respectively, of fees and interest due for spent nuclear fuel disposal costs, a positive $13.2 million for NU of net changes in fair value of hedged debt and a negative $5.4 million and $4.8 million for NU and CL&P, respectively, of net unamortized premium and discount as of December 31, 2009.

(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 2009 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 $12.5 million and $11.8 million for NU and CL&P, respectively, as of December 31, 2009.

(e)

Amounts are not included on our consolidated balance sheets. Funding of pension obligations includes a $200 million potential contribution for 2011 that is subject to change. This amount and contributions in future plan years will depend on many factors, including the performance of existing plan assets, valuation of the plan's liabilities, and long-term discount rates.

(f)

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. On February 7, 2010, an explosion occurred at the construction site of Kleen Energy Systems, LLC s 620 MW generation project with which CL&P has a Contract for Differences (CfD) contract. This event could delay or change CL&P s estimated payments under the CfD contract. Currently, management cannot estimate the effects of this recent event on the amounts of CL&P s obligations under the CfD contract. Changes in the value of the CfD contract do not impact CL&P's net income. For further information, see Note 19, Subsequent

Event, and Note 7C, Commitments and Contingencies - Long-Term Contractual Arrangements, to the consolidated financial statements.

(g)

Excludes unrecognized tax benefits of $124.3 million for NU and $89 million for CL&P as of December 31, 2009, as we cannot make reasonable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities.

(h)

Amount represents open purchase orders, excluding those obligations that are included in the capital leases, operating leases, estimated future annual regulated company costs and the estimated future annual NU Enterprises costs. These payments are subject to change as certain purchase orders include estimates based on projected quantities of material and/or services that are provided on demand, the timing of which cannot be determined. Because payment timing cannot be determined, we include all open purchase order amounts in 2010.

(i)

For NU, excludes other long-term liabilities, including a significant portion of the unrecognized tax benefits described above, deferred contractual obligations ($166.2 million), environmental reserves ($26 million), various injuries and damages reserves ($36.9 million), employee medical insurance reserves ($6.5 million), long-term disability insurance reserves ($11.8 million) and the asset retirement obligation (ARO) liability reserves ($50.6 million) as we cannot make reasonable estimates of the timing of payments. For CL&P, excludes unrecognized tax benefits described above, deferred contractual obligations ($114.5 million) environmental reserves ($2.7 million), various injuries and damages reserves ($24.3 million), employee medical insurance reserves ($2.1 million), long-term disability insurance reserves ($3.6 million) and the ARO liability reserves ($28.6 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 are also not included in this table. 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 7C, "Commitments and Contingencies - Long-Term Contractual Arrangements," Note 10, "Leases," and Note 11, "Long-Term Debt," to the consolidated financial statements.

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

RESULTS OF OPERATIONS - NU

The components of significant income statement variances, higher/(lower) in comparison to the previous year, are provided in the table below.

Income Statement Variances	**2009 versus 2008**		**2008 versus 2007**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (361)	(6)%	$ (22)	- %
Operating Expenses:				
Fuel, purchased and net interchange power	(367)	(12)	(354)	(11)
Other operation	(20)	(2)	60	6
Maintenance	(20)	(8)	43	20
Depreciation	31	11	13	5
Amortization of regulatory assets, net	(173)	(93)	146	(a)
Amortization of rate reduction bonds	13	6	4	2
Taxes other than income taxes	15	5	15	6
Total operating expenses	(521)	(10)	(73)	(1)
Operating income	160	27	51	10
Interest expense, net	4	2	29	12
Other income, net	(13)	(25)	(11)	(18)
Income from continuing operations before income tax expense	143	39	11	3
Income tax expense/(benefit)	74	70	(4)	(3)
Income from continuing operations	69	26	15	6
Income from discontinued operations	-	-	(1)	(100)
Net income	69	26	14	6
Preferred dividends of subsidiary	-	-	-	-
Net income attributable to controlling interest	$ 69	27 %	$ 14	6 %

(a) Percent greater than 100 not shown since not meaningful.

Net income was $69 million higher for 2009 as compared to 2008 due primarily to the absence of a $29.8 million after-tax litigation settlement charge in 2008 and higher transmission and distribution earnings. Net income was $14 million higher in 2008 as compared to 2007 due primarily to the growth in the Company's transmission segment, partially offset by the $29.8 million after-tax litigation settlement charge.

Comparison of 2009 to 2008

Operating Revenues

	For the Twelve Months Ended December 31,		
(Millions of Dollars)	**2009**	**2008**	**Variance**
Electric distribution	$ 4,359	$ 4,716	$ (357)
Gas distribution	449	577	(128)
Total distribution	4,808	5,293	(485)
Transmission	578	425	153
Regulated companies	5,386	5,718	(332)
Competitive businesses	81	114	(33)
Other & Eliminations	(28)	(32)	4
NU	$ 5,439	$ 5,800	$ (361)

Operating revenues decreased $361 million in 2009 due primarily to lower distribution revenues from the regulated companies ($485 million) as a result of the recovery of a lower level of electric and gas distribution fuel and other expenses passed through to customers through regulatory tracking mechanisms.

Electric distribution revenues decreased $357 million due primarily to a decrease in the portion of electric distribution revenues that does not impact earnings ($395 million), partially offset by an increase in the component of revenues that impacts earnings ($37 million). The portion of electric distribution segment revenues that impacts earnings increased $37 million due primarily to higher CL&P and PSNH retail rates, partially offset by lower retail electric sales. Retail electric sales for the regulated companies decreased 3.5 percent. Gas distribution revenues decreased $128 million due primarily to decreased recovery of fuel costs primarily as a result of lower prices, partially offset by higher sales volumes. Firm natural gas sales increased 6.9 percent in 2009 compared with 2008.

The $395 million decrease in electric distribution revenues that does not impact earnings consists of the portions of distribution revenues that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs ($356 million) and revenues that are eliminated in consolidation of the regulated companies ($39 million). The distribution revenue tracking components decreased $356 million due primarily to lower recovery of generation service and related congestion charges ($331 million) and lower CL&P wholesale revenues as a result of decreased market revenue related to sales of Independent Power Producers (IPP) purchased generation output ($163 million), partially offset by higher retail transmission revenues ($104 million) mainly as a result of the higher 2009 retail rates. 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 $153 million due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008 and higher overall expenses. Competitive businesses' revenues decreased $33 million due primarily to lower Boulos revenues as a result of less work on transmission projects and a lower level of work in other areas.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $367 million in 2009 due primarily to lower costs at the regulated companies. Fuel and purchased power expense from the regulated companies decreased at CL&P ($155 million) due to lower GSC supply costs and other purchased power costs, partially offset by an increase in deferred fuel costs, at Yankee Gas ($133 million) due to a decrease in gas prices in 2009 as compared to 2008, at WMECO ($45 million) due primarily to lower Basic/Default supply costs, and at PSNH ($38 million) due to an increased level of migration of ES customers to competitive supply and lower retail sales, partially offset by higher forward energy market prices.

Other Operation

Other operation expenses decreased $20 million in 2009 due primarily to lower NU parent and other companies' expenses ($49 million) and lower competitive businesses' expenses ($39 million), partially offset by higher regulated companies' distribution and transmission segment expenses ($68 million).

NU parent and other companies' expenses were lower by $49 million in 2009 due primarily to the absence of the $49.5 million payment resulting from the settlement of litigation made in 2008 ($29.8 million after-tax). Competitive businesses' expenses were lower by $39 million due primarily to lower Boulos expenses as a result of a lower level of work.

Higher regulated companies' distribution and transmission segment expenses of $68 million were due primarily to higher electric distribution segment expenses ($49 million), higher expenses at Yankee ($18 million), and higher transmission segment expenses ($15 million), partially offset by lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($8 million), and all other operating costs ($6 million). The higher operations expenses impacting earnings include higher uncollectible and pension expenses.

Maintenance

Maintenance expenses decreased $20 million in 2009 due primarily to lower regulated companies' distribution expenses ($21 million), partially offset by higher transmission line expenses ($1 million). Distribution expenses were lower due primarily to lower repair and maintenance of distribution lines ($15 million), including lower storm-related expenses, lower equipment maintenance expenses ($4 million), and lower PSNH generation expenses ($3 million), partially offset by higher vegetation management expenses ($5 million).

Depreciation

Depreciation expenses increased $31 million in 2009 due primarily to higher transmission ($23 million) and distribution ($11 million) plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net expenses decreased $173 million in 2009 for the distribution segment due primarily to lower amortization at CL&P resulting from a lower recovery of stranded costs ($131 million) as a result of lower retail CTA revenues and higher transition costs, partially offset by higher amortization of the SBC balance ($15 million). The decreases for PSNH and WMECO are $39 million and $15 million, respectively.

Amortization of Rate Reduction Bonds

Amortization of RRBs expenses increased $13 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other than Income Taxes

Taxes other than income taxes expenses increased $15 million in 2009 due primarily to higher property taxes ($18 million) as a result of higher plant balances and increased municipal tax rates and higher payroll related taxes, partially offset by the resolution of various routine tax issues primarily surrounding sales and use tax amounts ($8 million).

Interest Expense, Net

Interest expense, net increased $4 million in 2009 due primarily to higher long-term debt interest ($31 million) resulting from the issuance of new long-term debt in 2008 and 2009, partially offset by lower RRB interest resulting from lower principal balances outstanding ($14 million), and lower other interest ($13 million) mostly related to the resolution of various routine tax issues.

Other Income, Net

Other income, net decreased $13 million in 2009 due primarily to lower AFUDC equity income ($20 million) as a result of lower eligible CWIP balances, the absence of interest income related to the federal tax settlement in 2008 ($10 million), and lower CL&P Energy Independence Act incentives ($6 million), partially offset by higher investment income due primarily to improved results from NU's supplemental benefit trust and the absence of other-than-temporary impairments recorded in 2008 ($24 million).

Income Tax Expense

Income tax expense increased $74 million in 2009 due primarily to higher pre-tax earnings ($50 million), lower tax benefits associated with less capital expenditures ($10 million), lower federal and state tax credits ($4 million), and increases in allowance for uncollectible accounts reserves ($3 million).

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	$ 5,800	$ 5,822	$ (22)

Operating revenues decreased $22 million in 2008 due primarily 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 due primarily 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 due primarily to lower electric distribution revenues ($213 million), partially offset by higher gas distribution revenues ($63 million). Transmission segment revenues increased $113 million due primarily 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 due primarily 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 impacts earnings ($68 million). The portion of the electric distribution segment revenues that impacts earnings increased $68 million due primarily 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 due primarily to increased recovery of fuel 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 was due to the portions of distribution 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 due primarily to lower 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 due primarily to an increase in the market revenue 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 retail 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 and purchased power 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 due primarily 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) due primarily to higher fuel prices in 2008 and higher PSNH fuel expense ($28 million) due primarily 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 expenses increased $60 million in 2008 due primarily 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 were higher by $54 million in 2008 due primarily to the absence of the $49.5 million payment resulting from the settlement of litigation. Competitive businesses' expenses were higher by $6 million due primarily to higher operating costs at the remaining services businesses.

Higher regulated companies' distribution and transmission segment expenses of $1 million were due primarily to higher transmission segment expenses ($8 million), expenses at Yankee ($6 million) and higher electric distribution segment expenses ($4 million), partially offset by all other operating costs ($18 million).

Maintenance

Maintenance expenses increased $43 million in 2008 due primarily to higher regulated companies' distribution expenses ($38 million) and higher transmission line expenses ($4 million). Distribution expenses were $38 million higher due primarily to higher PSNH generation expenses ($15 million) mainly related to the Merrimack Station maintenance outages, higher vegetation management ($9 million), higher overhead line maintenance expenses ($5 million), substation equipment ($3 million) and line transformers ($2 million).

Depreciation

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

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net expenses increased $146 million in 2008 for the distribution segment due primarily to higher amortization at CL&P ($144 million) resulting from a higher recovery of transition costs ($62 million), higher amortization of the SBC balance ($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 expenses increased $4 million in 2008, which corresponds to the reduction in principal of the 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 expenses increased $15 million in 2008 due primarily 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 due primarily 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 due primarily to lower investment income ($16 million) due primarily 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) due primarily to NU s 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 federal tax settlement in 2008 ($10 million).

Income Tax Expense

Income tax expense decreased $4 million in 2008 due primarily to the settlement of litigation ($20 million), flow-through items related to depreciation ($6 million), partially offset by impacts associated with higher pre-tax earnings ($22 million).

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

The components of significant income statement variances, higher/(lower) in comparison to the previous year, are provided in the table below.

Income Statement Variances	**2009 versus 2008**		**2008 versus 2007**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (134)	(4)%	$ (123)	(3)%
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(155)	(8)	(432)	(19)
Other operation	13	2	22	4
Maintenance	(12)	(10)	22	21
Depreciation	24	15	11	7
Amortization of regulatory assets, net	(118)	(72)	144	(a)
Amortization of rate reduction bonds	10	7	10	7
Taxes other than income taxes	12	7	11	7
Total operating expenses	(226)	(7)	(212)	(6)
Operating Income	92	25	89	31
Interest expense, net	10	7	8	6
Other income, net	(16)	(38)	2	5
Income before income tax expense	66	25	83	45
Income tax expense	41	53	25	49
Net income	$ 25	13 %	$ 58	43 %

(a) Percent greater than 100 not shown since not meaningful.

Comparison of the Year 2009 to the Year 2008

Operating Revenues

Operating revenues decreased $134 million in 2009 due to lower distribution segment revenues ($264 million), partially offset by higher transmission segment revenues ($130 million).

The distribution segment revenues decreased $264 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($289 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings increased $25 million.

The $289 million decrease in distribution segment revenues that does not impact earnings was due primarily to a decrease in the portions of retail revenues that are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs through CL&P's tariffs ($265 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($24 million). The distribution revenues included in DPUC approved tracking mechanisms decreased $265 million due primarily to a decrease in revenues associated with the recovery of GSC and supply-related FMCC ($184 million) and lower wholesale revenues as a result of decreased market revenue related to sales of CL&P's IPP purchased generation output to ISO-NE due to a decrease in the market price of energy ($163 million), partially offset by higher retail transmission revenues ($75 million). The lower GSC and supply-related FMCC revenue was due primarily to lower retail sales, lower customer rates resulting from lower average supply prices and additional customer migration to third-party suppliers in 2009 as compared to 2008. 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 revenues that impacts earnings increased $25 million primarily as a result of rate changes, partially offset by lower retail sales. The 2009 retail sales as compared to the same period in 2008 decreased 17.6 percent for the industrial, 2.9 percent for the commercial, and 0.7 percent for the residential classes. Total retail sales decreased overall by 3.8 percent.

Transmission segment revenues increased $130 million due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008 and higher overall expenses.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $155 million in 2009 due primarily to lower GSC supply costs ($280 million) and other purchased power costs ($41 million), partially offset by an increase in deferred fuel costs ($165 million), all of which are included in DPUC approved tracking mechanisms. The $280 million decrease in GSC supply costs was due primarily to lower retail sales, lower average supply prices and additional customer migration to third-party suppliers. These GSC supply costs are the contractual amounts CL&P must pay to various suppliers that have been awarded the right to supply SS and LRS load through a competitive solicitation process. The $165 million increase in deferred fuel costs was due primarily to the combined effect of the twelve months of 2008 net underrecovery of GSC and FMCC expenses as compared to the twelve months of 2009 net overrecovery of these expenses.

Other Operation

Other operation expenses increased $13 million in 2009 as a result of higher distribution segment expenses ($36 million) due primarily to pension and expenses related to uncollectible receivable balances, and higher transmission segment expenses, which are tracked and recorded through FERC rate tariffs ($14 million), partially offset by lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($30 million), and lower transmission segment intracompany billing to the distribution segment that are eliminated in consolidation ($6 million).

Maintenance

Maintenance expenses decreased $12 million in 2009 due primarily to lower repair and maintenance of distribution lines ($6 million), including lower storm expenses, lower distribution substation equipment expenses ($2 million), lower transmission segment expenses ($1 million), and lower transformer maintenance expenses ($1 million).

Depreciation

Depreciation expenses increased $24 million in 2009 due primarily to higher utility plant balances resulting from completed construction projects placed into service in the transmission segment ($19 million) and the distribution segment ($5 million).

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net expenses decreased $118 million in 2009 due primarily to lower amortization related to the recovery of stranded charges ($131 million) as a result of lower retail CTA revenue and higher transition costs, partially offset by higher amortization of the SBC balance ($15 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs expenses increased $10 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes expenses increased $12 million in 2009 due primarily to higher property taxes as a result of higher plant balances and increased municipal tax rates ($10 million), higher gross earnings taxes ($4 million) recoverable in rates mainly as a result of higher transmission revenues that are subject to gross earnings tax, and higher payroll taxes ($2 million), partially offset by the resolution of various routine tax issues primarily surrounding sales and use tax amounts ($4 million).

Interest Expense, Net

Interest expense, net increased $10 million in 2009 due primarily to higher long-term debt interest ($28 million) resulting from the $300 million debt issuance in May 2008 and the $250 million debt issuance in February 2009, partially offset by lower other interest ($9 million) mostly related to the resolution of various routine tax issues, and lower RRB interest resulting from lower principal balances outstanding ($10 million).

Other Income, Net

Other income, net decreased $16 million in 2009 due primarily to lower AFUDC equity income ($18 million) as a result of lower eligible CWIP due to large transmission projects being completed and placed in-service in 2008 and lower capital expenditures in 2009, the absence in 2009 of interest income related to a federal tax settlement in 2008 ($6 million), and lower Energy Independence Act incentives ($6 million), partially offset by higher investment income due primarily to improved results from NU's supplemental benefit trust and the absence of other-than-temporary impairments recorded in 2008 ($16 million).

Income Tax Expense

Income tax expense increased $41 million due primarily to higher pre-tax earnings ($23 million), less tax benefits as a result of lower capital expenditures ($9 million), lower state tax credits ($3 million), and increases in allowance for doubtful accounts reserves ($4 million).

Comparison of the Year 2008 to the Year 2007

Operating Revenues

Operating revenues decreased $123 million in 2008 due to lower distribution segment revenues ($233 million), partially offset by higher transmission segment revenues ($110 million).

The distribution segment revenues decreased $233 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($296 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intercompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings increased $62 million.

The $296 million decrease in distribution segment revenue that does not impact earnings was due primarily to the portions of retail revenues that are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs through CL&P tariffs ($217 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($78 million). The distribution revenue included in DPUC approved tracking mechanisms decreased $217 million due primarily to a decrease in revenues associated with the recovery of GSC and supply-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 supply-related FMCC revenue was due primarily 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 due primarily to a decrease in this rate component in 2008 as a result of lower reliability must run (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 revenues that impacts earnings increased $62 million due primarily 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 due primarily 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 expenses decreased $432 million in 2008 due primarily to lower 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 due primarily 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 been awarded the right to supply standard service (SS) and last resort service (LRS) load through a competitive solicitation process. The $174 million decrease in deferred fuel costs was due primarily 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 in 2008 as a result of higher costs that are recovered through distribution tracking mechanisms and have no earnings impact ($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 Energy Independence Act (EIA) expenses ($6 million). In addition, there were higher transmission segment expenses ($5 million), partially offset by lower transmission segment intracompany billing to the distribution segment that are eliminated in consolidation ($80 million), and lower distribution segment expenses ($8 million) due primarily 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 due primarily to higher distribution overhead lines ($10 million), due primarily to more storms in 2008 compared to 2007, higher vegetation management expenses ($6 million), higher transmission segment expenses ($4 million), and higher distribution substation equipment expenses ($2 million).

Depreciation

Depreciation expenses increased $11 million in 2008 due primarily to higher utility plant balances resulting from completed construction programs placed into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net expenses increased $144 million in 2008 due primarily 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 expenses increased $10 million in 2008, which corresponded to the reduction in principle of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes expenses increased $11 million in 2008 due primarily to higher gross earnings taxes recoverable in rates as a result of higher distribution revenues that are subject to gross earnings tax ($13 million) and higher property taxes as a result of increased plant balances and increased 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 in 2008 due primarily 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 in 2008 due primarily to 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 federal tax settlement in 2008 ($6 million) and higher EIA incentives ($2 million), partially offset by higher investment losses ($10 million) due primarily to the NU supplemental benefit trust, a decrease in conservation and load management (C&LM) incentive income ($3 million), and a decrease in investment income ($2 million).

Income Tax Expense

Income tax expense increased $25 million in 2008 due primarily to higher pre-tax earnings being subject to tax at marginal rates, partially offset by flow-through items associated with property plant and equipment differences and uncollectible account reserves, thereby reducing the effective tax rate.

LIQUIDITY

CL&P had cash flows from operating activities in 2009 of $482.2 million, compared with operating cash flows of $267.3 million in 2008 and $4.5 million in 2007 (all amounts are net of RRB payments, which are included in financing activities). The improved cash flows in 2009 were due primarily to higher transmission revenues after significant projects were placed in service in late 2008 as well as cost management efforts; a decrease of approximately $200 million related primarily to amounts spent on the FMCC, GSC and C&LM, the costs of which are passed on to customers; a cash flow increase due to improved collections of accounts receivable in 2009 offset by increases in the negative cash flow effect of our accounts payable balances related to operating activities and change in the amount of income tax refunds or payments. We project cash flows provided by operating activities at CL&P of approximately $440 million in 2010, net of RRB payments.

In 2009, CL&P reduced its borrowings under the $400 million credit facility it shares with the other regulated companies by $188 million. CL&P can borrow up to $200 million under this facility. Other financing activities in 2009 included the $250 million bond issuance in February 2009, the remarketing of $62 million of tax-exempt PCRBs and cash capital contributions from NU parent of $147.6 million, offset by $102.7 million in repayment of NU Money Pool borrowings and $113.8 million in common dividends paid to NU parent.

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 $435.7 million in 2009, compared with $849.5 million in 2008. This decrease was primarily the result of lower transmission segment capital expenditures in 2009 due to the completion in 2008 of three major transmission projects in southwest Connecticut. Other investing activities in 2009 included lendings to the NU Money Pool of $97.8 million. We project capital expenditures at CL&P of $441 million in 2010 (including non-cash factors).

While the impact of continued market volatility and the extent and impacts of the declining economic environment cannot be predicted, we are confident that CL&P currently has operating flexibility and access to funding sources to maintain adequate liquidity. In the second half of 2009, all three rating agencies reaffirmed all of their existing credit ratings and stable outlooks on CL&P. On January 22, 2010, Fitch downgraded CL&P s preferred stock rating from BBB to BBB- as a result of revised guidelines for rating preferred stock and hybrid securities in general. Capital contributions from NU parent and other internal sources of funding are provided to CL&P as necessary. CL&P has the mandatory tender of $62 million in 2010, which it plans to remarket, but does not have any long-term debt maturities until 2014, and there are no CL&P debt issuances planned for 2010.

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

The components of significant income statement variances, higher/(lower) in comparison to the previous year, are provided in the table below.

Income Statement Variances	**2009 versus 2008**		**2008 versus 2007**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (31)	(3)%	$ 58	5 %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(38)	(7)	28	5
Other operation	24	11	7	3
Maintenance	(4)	(4)	17	23
Depreciation	6	10	3	6
Amortization of regulatory (liabilities)/assets, net	(39)	(a)	2	24
Amortization of rate reduction bonds	2	4	(7)	(13)
Taxes other than income taxes	6	13	2	7
Total operating expenses	(43)	(4)	52	5
Operating Income	12	9	6	5
Interest expense, net	(4)	(7)	4	8
Other income, net	2	30	1	9
Income before income tax expense	18	22	3	4
Income tax expense	10	45	(1)	(4)
Net income	$ 8	13 %	$ 4	7 %

(a)

Percent greater than 100 not shown since not meaningful.

<u>Comparison of the Year 2009 to the Year 2008</u>

Operating Revenues

Operating revenues decreased $31 million in 2009 due to lower distribution segment revenues ($46 million), partially offset by higher transmission segment revenues ($15 million).

The distribution segment revenues decreased $46 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($57 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings increased $11 million primarily as a result of higher retail rates, partially offset by lower retail sales volumes. The 2009 retail sales as compared to the same period in 2008 decreased 8.2 percent for the industrial, 1.5 percent for the commercial, and 0.2 percent for the residential classes. Total retail sales decreased overall by 2.2 percent.

The $57 million decrease in the portion of distribution segment revenues that does not impact earnings was due primarily to a decrease in the portions of retail revenues that are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs through PSNH's tariffs ($47 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($9 million). The distribution revenues included in NHPUC approved tracking mechanisms decreased $47 million due primarily to lower purchased fuel and power costs ($99 million), partially offset by an increase in the SCRC ($27 million), higher retail transmission revenues ($14 million), higher wholesale revenue ($8 million), and higher Northern Wood Power Plant renewable energy certificate revenues ($4 million). 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 $15 million due primarily to a higher transmission investment base and higher expenses.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs decreased $38 million in 2009 due primarily to an increased level of migration of ES customers to competitive supply and lower retail sales, partially offset by higher forward energy market prices.

Other Operation

Other operation expenses increased $24 million in 2009 as a result of higher distribution segment expenses ($15 million), mainly as a result of higher administrative and general expenses, including higher pension and medical costs, and higher expenses related to uncollectible receivable balances, and higher retail transmission expenses that are recovered through distribution tracking mechanisms and have no earnings impact ($10 million).

Maintenance

Maintenance expenses decreased $4 million in 2009 due primarily to lower repair and maintenance of distribution lines ($7 million), including lower storm costs, lower generation expenses primarily as a result of lower maintenance outage expenses at Merrimack Station ($2 million) and hydro expenses incurred in 2008 primarily as a result of two major dam resurfacing projects ($1 million), partially offset by higher vegetation management expenses ($5 million).

Depreciation

Depreciation expense increased $6 million in 2009 due primarily to higher utility plant balances resulting from completed construction projects placed into service in the distribution segment ($3 million) and the transmission segment ($2 million).

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net expense decreased $39 million in 2009 due primarily to a decrease in net deferrals associated with the ES and TCAM tracking mechanisms, partially offset by an increase in net deferrals associated with the SCRC tracking mechanism.

Amortization of Rate Reduction Bonds

Amortization of RRBs expense increased $2 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes expenses increased $6 million in 2009 due primarily to higher property taxes as a result of higher net plant balances and increased local municipal tax rates ($7 million), partially offset by lower sales taxes as a result of the resolution of various routine tax issues ($1 million).

Interest Expense, Net

Interest expense, net decreased $4 million in 2009 due primarily to lower RRB interest resulting from lower principal balances outstanding ($3 million) and lower other interest ($1 million) mostly related to the resolution of various routine tax issues.

Other Income, Net

Other income, net increased $2 million in 2009 due primarily to higher investment income related to improved results from the NU supplemental benefit trust and the absence of other-than-temporary impairments recorded in 2008, and higher interest income related to the return on the December 2008 ice storm, partially offset by the absence in 2009 of interest income related to a federal tax settlement in 2008 and lower AFUDC equity income due to higher short-term debt, which resulted in a lower rate based on borrowing costs.

Income Tax Expense

Income tax expense increased $10 million in 2009 due primarily to higher pre-tax earnings ($6 million) and less favorable depreciation deduction adjustments ($2 million).

Comparison of the Year 2008 to the Year 2007

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 due primarily to an increase in the portion of distribution revenues that does not impact earnings ($37 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and consolidation eliminations of transmission segment intracompany billings to the distribution segment. The portion of revenues that impacts 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 2007.

The $37 million increase in distribution segment revenues that does not impact earnings was due primarily to an increase in the portions of retail revenues that are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs ($55 million) through PSNH s tariffs, partially offset by transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($18 million). The distribution revenue included in NHPUC approved tracking mechanisms increased $55 million due primarily to the pass-through of higher purchased fuel and power 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) due primarily 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 due primarily 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 in 2008 due primarily 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 in 2008 as a result of higher costs that are recovered through distribution tracking mechanisms and have no earnings impact ($13 million) due primarily to retail transmission. In addition, there were higher distribution segment expenses ($10 million) due primarily to higher customer account and storm restoration expenses, and higher transmission segment expenses ($2 million), partially offset by lower transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($18 million).

Maintenance

Maintenance expenses increased $17 million in 2008 due primarily 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 due primarily 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 in 2008 due primarily to higher utility plant balances resulting from completed construction programs placed into service.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net expense increased $2 million in 2008 primarily as a result of increased recoveries of previously deferred storm costs.

Amortization of Rate Reduction Bonds

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

Taxes Other Than Income Taxes

Taxes other than income taxes expenses increased $2 million in 2008 due primarily 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 in 2008 due primarily 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 in 2008 due primarily 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 federal tax settlement in 2008 ($2 million), partially offset by higher investment losses ($2 million) due primarily to the NU supplement benefit trust and lower investment income ($1 million).

Income Tax Expense

Income tax expense decreased $1 million in 2008 due primarily to lower flow-through items related to property, plant and equipment, partially offset by higher pre-tax earnings.

LIQUIDITY

PSNH had cash flows provided by operating activities in 2009 of $58.2 million, compared with operating cash flows of $116.4 million in 2008 and $95.5 million in 2007, all amounts are net of RRB payments included in financing activities. The decrease in 2009 operating cash flows is due primarily to an increase of $119.7 million in the negative cash flow effect of accounts payable balances as a result of, among other things, costs related to the major storm in December 2008 that were paid to vendors in 2009 and deferred. These costs are currently recovered from customers at an annual rate of $6 million, beginning August 1, 2009, pursuant to the temporary rate case settlement. This level of recovery could be modified once PSNH's permanent distribution rate case is decided in mid-2010. In addition, the 2009 operating cash flow decrease was due to the $11.7 million change in the amount of income tax refunds or payments. The operating cash flow decrease was offset by improved operating results, insurance settlement proceeds and a decrease in the negative cash flow impact from various other working capital items, such as fuel, materials and supplies of $26.3 million.

RESULTS OF OPERATIONS - WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

The components of significant income statement variances, higher/(lower) in comparison to the previous year, are provided in the table below.

Income Statement Variances	**2009 versus 2008**		**2008 versus 2007**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (39)	(9)%	$ (23)	(5)%
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(45)	(19)	1	-
Other operation	9	11	(22)	(22)
Maintenance	(3)	(14)	2	11
Depreciation	1	7	-	-
Amortization of regulatory (liabilities)/assets, net	(15)	(a)	2	17
Amortization of rate reduction bonds	1	7	1	7
Taxes other than income taxes	1	10	-	-
Total operating expenses	(51)	(13)	(16)	(4)
Operating Income	12	26	(7)	(14)
Interest expense, net	-	-	-	-
Other income, net	-	-	(2)	(50)
Income before income tax expense	12	42	(9)	(24)
Income tax expense	4	42	(4)	(28)
Net income	$ 8	43 %	$ (5)	(22)%

(a) Percent greater than 100 not shown since not meaningful.

<u>Comparison of the Year 2009 to the Year 2008</u>

Operating Revenues

Operating revenues decreased $39 million in 2009 due to lower distribution segment revenues ($47 million), partially offset by higher transmission segment revenues ($8 million).

The distribution segment revenues decreased $47 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($49 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings increased $1 million.

The $49 million distribution segment revenues decrease that does not impact earnings was due primarily to a decrease in the portions of retail revenues that are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs through WMECO's tariffs ($44 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($5 million). The distribution revenues included in DPU approved tracking mechanisms decreased $44 million due primarily to lower energy supply costs ($48 million), lower transition cost recoveries ($10 million), and lower wholesale revenues ($5 million), partially offset by higher retail transmission revenues ($15 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The 2009 retail sales as compared to the same period in 2008 decreased 11.7 percent for the industrial, 4.8 percent for the commercial, and 1.6 percent for the residential classes. Total retail sales decreased overall by 4.8 percent.

Transmission segment revenues increased $8 million due primarily to a higher transmission investment base and higher expenses.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $45 million in 2009 due primarily to lower Basic/Default Service supply costs ($47 million) and lower other purchased power costs ($2 million), partially offset by higher deferral of excess Basic/Default Service revenue over Basic/Default Service expense ($4 million). The Basic/Default Service supply costs are the contractual amounts we must pay to various suppliers that serve this load after winning a competitive solicitation process. These costs decreased as a result of lower supplier contract rates and reduced load volumes. To the extent that these costs do not match the revenues collected from customers, the DPU allows the difference to be deferred for future collection or refund. Lower other purchased power costs are due primarily to a decrease in costs associated with customer generation and IPPs.

Other Operation

Other operation expenses increased $9 million in 2009 as a result of higher retail transmission and other costs that are recovered through distribution tracking mechanisms and have no earnings impact ($11 million), partially offset by lower distribution segment expenses ($2 million) mainly as a result of lower administrative and general expenses.

Maintenance

Maintenance expenses decreased $3 million in 2009 due primarily to lower repair and maintenance of distribution lines including lower storm expenses and lower vegetation management expense.

Depreciation

Depreciation expenses increased $1 million in 2009 due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net expenses decreased $15 million in 2009 due primarily to the deferral of allowed transition costs that are in excess of transition revenues, resulting from a decrease in the transition cost portion of the rate and lower IPP revenue than previous years.

Amortization of Rate Reduction Bonds

Amortization of RRBs expenses increased $1 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes expenses increased $1 million in 2009 due primarily to higher property taxes as a result of higher plant balances and increased municipal tax rates.

Income Tax Expense

Income tax expense increased $4 million due primarily to higher pre-tax earnings.

<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 due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($24 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings decreased $2 million.

The $24 million decrease in distribution segment revenues that does not impact earnings was due primarily to a decrease in the portions of retail revenues that are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs through WMECO s tariffs ($18 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($6 million). The distribution revenue included in DPU approved tracking mechanisms decreased $18 million due primarily to lower retail transmission revenues ($12 million) and lower pension tracker and default service true-up revenues ($8 million). 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 revenues that impacts earnings decreased $2 million due primarily 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 2007.

Transmission segment revenues increased $3 million due primarily 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 expenses increased $1 million in 2008 due primarily to higher Basic/Default 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 from customers.

Other Operation

Other operation expenses decreased $22 million in 2008 as a result of lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($20 million) such as retail transmission ($11 million) and lower tracked administrative and general expenses mainly due to pension expense ($9 million). In addition, transmission segment intracompany billings to the distribution segment that are eliminated in consolidation reduced expenses ($6 million), partially offset by higher distribution segment expenses ($2 million) due primarily to higher uncollectible expenses and higher transmission segment expenses ($1 million).

Maintenance

Maintenance expenses increased $2 million in 2008 due primarily to vegetation management expenses as a result of storms.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net expenses increased $2 million in 2008 due primarily 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 expenses increased $1 million in 2008, which corresponded to the reduction in principal of the RRBs.

Other Income, Net

Other income, net decreased $2 million in 2008 due primarily to higher investment losses ($2 million) due primarily to the NU supplemental benefit trust and lower investment income ($2 million), partially offset by higher interest income related to the federal tax settlement in 2008 ($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 in 2008 due primarily to lower pre-tax earnings.

LIQUIDITY

WMECO had cash flows provided by operating activities in 2009 of $47.7 million, compared with operating cash flows of $53.9 million in 2008 and $24.9 million in 2007, all amounts are net of RRB payments included in financing activities. The decrease in 2009 cash flows was due to an increase of $41.6 million in the negative cash flow effect of accounts payable balances partially as a result of costs related to the major storm in December 2008 that were paid to vendors in 2009. These costs were deferred and are expected to be recovered from customers. WMECO anticipates filing a distribution rate case in mid-2010, which would include a request for the timely recovery of the December 2008 storm costs. This impact was offset by a decrease in the negative cash flow from various other working capital items, such as accounts receivable and unbilled revenues of $18 million, and improved operating results.

Item 7A.

Quantitative and Qualitative Disclosures about Market Risk

Market Risk Information

Commodity Price Risk Management: 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 energy sales contract with NYMPA through 2013 with approximately 0.4 million remaining MWh of supply contract volumes, net of related sales volumes. Select Energy also has a non-derivative energy contract that expires in mid-2012 to purchase output from a generation facility, which is less exposed to market price volatility and is not included in the sensitivity analysis below. As Select Energy's contract volumes are winding down, and as the NYMPA contract is substantially hedged against price risks, we have limited exposure to commodity price risks. We have no energy contracts entered into for trading purposes.

For Select Energy's wholesale energy portfolio derivatives, 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 pre-tax earnings and fair values from our market risk-sensitive contracts due to one or more hypothetical changes in commodity price components, or other similar price changes. Under the sensitivity analysis, the fair value of the derivatives 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.

Select Energy's Wholesale Portfolio: When conducting sensitivity analyses of the change in the fair value of the wholesale energy portfolio, which includes several derivative contracts, which would result from a hypothetical change in the future market price of electricity, the fair values of the energy 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.

Hypothetical changes in the fair value of derivative contracts in the wholesale portfolio were determined using a 30 percent assumed change in forward market prices. As of December 31, 2009, we determined the following hypothetical changes and calculated the nominal adjusted impact on pre-tax earnings:

(Millions of Dollars) **Commodity**	**30% Price Increase Nominal Impact on Pre-Tax Earnings**	**30% Price Decrease Nominal Impact on Pre-Tax Earnings**

Energy	$ 1.3	$ (3.1)
Capacity	(1.7)	1.7
Ancillaries	(1.6)	1.6
	$ (2.0)	$ (0.2)

The impact of a change in electricity prices on wholesale derivative transactions as of December 31, 2009 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 energy 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. As of December 31, 2009, approximately 93 percent (87 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. As of December 31, 2009, 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 members of management from other areas of NU that do not 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 event 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.

Due to the exposure of counterparties to Select Energy, Select Energy had cash collateral balances deposited with its NYMEX broker of $28.1 million and $26.3 million as of December 31, 2009 and 2008, respectively, which are included in Current assets - prepayments and other on the accompanying consolidated balance sheets. As of December 31, 2009, Select Energy also had $2.1 million of collateral posted with a counterparty under a master netting agreement. This collateral is netted against the fair value of its net derivative position. Select Energy held no collateral balances received from counterparties as of December 31, 2009 and 2008. In addition, Select Energy had posted a $2 million NU parent LOC as of December 31, 2009 in favor of ISO-NE.

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. As of December 31, 2009, CL&P had $0.5 million in cash collateral deposited with a counterparty that has been netted against the fair value of the related derivative. As of December 31, 2008, our regulated companies neither held cash collateral nor deposited collateral with counterparties. NU parent provides standby LOCs for the benefit of its subsidiaries under its revolving credit agreement. PSNH posts such LOCs as collateral with counterparties and ISO-NE. As of December 31, 2009, PSNH had posted $39 million in such NU parent LOCs.

We have implemented an Enterprise Risk Management (ERM) methodology for identifying the principal risks of the Company. ERM involves the application of a well-defined, enterprise-wide methodology that enables 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 or manage every risk or event that could impact our financial condition or results of operations. The findings of this process are periodically discussed with our Board of Trustees.

Additional quantitative and qualitative disclosures about market risk are set forth in Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, included in this 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 Consolidated 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 8A.

Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

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

Item 8B.

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, CL&P, PSNH and WMECO s internal controls over financial reporting were audited by Deloitte & Touche LLP.

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, 2009.

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, 2009 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Item 9.

Other Information

No information is required to be disclosed under this item as of December 31, 2009, as this information has been previously disclosed in applicable reports on Form 8-K during the fourth quarter of 2009.

PART III

Item 10.

Directors, Executive Officers and Corporate Governance

The information in Item 10 is provided as of February 25, 2010 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 or about April 1, 2010.

NU and CL&P

The following table sets forth certain information as of February 25, 2010 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**
Jay S. Buth*	40	Vice President Accounting and Controller of NU and CL&P.
Gregory B. Butler	52	Senior Vice President and General Counsel of NU and CL&P.
Jeffrey D. Butler**	54	President and Chief Operating Officer and a Director of CL&P.
Jean M. LaVecchia***	58	Vice President - Human Resources of Northeast Utilities Service Company (NUSCO), a subsidiary of NU.
David R. McHale	49	Executive Vice President and Chief Financial Officer of NU and CL&P.

Leon J. Olivier	61	Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of CL&P.
James B. Robb***	49	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	64	Chairman of the Board, President and Chief Executive Officer of NU; Chairman of CL&P.

*

Mr. Buth was elected Vice President Accounting and Controller, effective June 9, 2009.

**

Mr. Butler was elected President and Chief Operating Officer and Director of CL&P effective July 1, 2009 and is therefore an executive officer solely of CL&P.

***

Deemed executive officer of NU and CL&P pursuant to Rule 3b-7 under the Securities Exchange Act of 1934.

Jay S. Buth. Mr. Buth became Vice President Accounting and Controller of NU, CL&P, PSNH and WMECO, effective June 9, 2009. Previously, Mr. Buth served as Controller, and Vice President and Controller at NJR Service Corporation, a subsidiary of New Jersey Resources Corporation, a gas utility holding company, from June 2006 to January 2009. He also served as Director Finance at Allegheny Energy, Inc. from May 2004 to May 2006.

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 CL&P, PSNH and WMECO April 22, 2009 and 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.

Jeffrey D. Butler. Mr. Butler became President and Chief Operating Officer and a Director of CL&P effective July 1, 2009. Previously, Mr. Butler was employed by Pacific Gas & Electric Company for approximately 28 years, most recently as Senior Vice President - Energy Delivery, before retiring in March 2008. Prior to his last assignment, Mr. Butler also held the positions of Senior Vice President - Transmission and Distribution, Vice President - Operations, Maintenance and Construction, and Vice President - Distribution Operations, Maintenance and Construction beginning in July 1997.

Jean M. LaVecchia. Ms. LaVecchia was elected Vice President - Human Resources of NUSCO, effective January 1, 2005 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009 and 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 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.

James B. Robb. Mr. Robb was elected Senior Vice President, Enterprise Planning and Development of NUSCO on September 4, 2007 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009. 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 for executive officers, Directors or Trustees will be posted on the website. Any such amendment or waiver would require the prior consent of the Board of Trustees 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, 2010, 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.

COMPENSATION DISCUSSION AND ANALYSIS

OVERALL OBJECTIVES OF EXECUTIVE COMPENSATION PROGRAM

General

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, 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.

The fundamental objective of NU s Executive Compensation Program is to motivate executives and key employees to support NU s strategy of investing in and operating businesses that benefit customers, employees, and shareholders. We are also responsible to our franchise customers to provide energy services reliably, safely, with respect for the environment and our employees, and at a reasonable cost.

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

- **Attract and retain key executives by providing total compensation competitive with that of other executives employed by companies of similar size and complexity.** The program relies on compensation data obtained from consultants surveys of companies and from a customized peer group to ensure that compensation opportunities are competitive and capable of attracting and retaining executives with the experience and talent required to achieve NU s strategic objectives. As NU continues to grow and improve its transmission, distribution, and 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 our customers and NU 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 consist of performance units (performance shares and performance cash) and restricted share units (RSUs). Performance units are paid out based on the achievement of corporate goals (cumulative net income, average return on equity, average credit rating and relative total shareholder return). The size of RSU grants may reflect corporate performance during the preceding fiscal year as well as individual performance and contribution, but the ultimate value of the RSUs is based on 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 we serve, government regulations, and long-term energy policies. In addition, utility companies rely on long-term capital investments to serve their customers.

As a result, public utilities benefit from long-term service employees. We have structured our 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.

NAMED EXECUTIVE OFFICERS

The executive officers of CL&P listed in the Summary Compensation Table in this Item 11 whose compensation is discussed in this Compensation Discussion and Analysis (CD&A) are CL&P s Chief Executive Officer (CEO), Executive Vice President and Chief Financial Officer (CFO), and the three other most highly compensated executive officers other than CL&P s CEO and CFO who were serving as executive officers at the end of 2009 (collectively, referred to as the "Named Executive Officers" or "NEOs.") Each Named Executive Officer of CL&P also serves as an executive officer of one or more subsidiaries of NU. Compensation for such NEOs discussed in this CD&A was for all services provided by such individuals in all capacities to NU and its subsidiaries. For 2009, CL&P s Named Executive Officers are:

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Leon J. Olivier, Chief Executive Officer of CL&P

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David R. McHale, Executive Vice President and Chief Financial Officer

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

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Gregory B. Butler, Senior Vice President and General Counsel

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James B. Robb, Senior Vice President-Enterprise Planning and Development of NUSCO

RISK ANALYSIS OF EXECUTIVE COMPENSATION PROGRAM

The overall compensation program features a mix of compensation elements ranging from a fixed base salary that is risk-neutral to annual and long-term incentive compensation programs intended to motivate officers and eligible employees to achieve individual and corporate performance goals that reflect the appropriate assessment of risk. The fundamental objective of the compensation program is to foster the continued growth and success of NU s business. The design and implementation of the overall compensation program provides NU s Compensation Committee with opportunities throughout the year to assess risks within the compensation program that may have a material effect on

NU and its shareholders.

Each year, as part of its annual planning process, NU s Board of Trustees and its Finance Committee review the company s comprehensive annual operating and five-year strategic plans. The annual operating plan consists of the goals and objectives for the year, key performance indicators and financial forecasts. The strategic plan consists of long-term corporate goals and objectives, specific strategies to achieve those goals, and action plans designed to implement each strategy. The Enterprise Risk Management (ERM) process is integrated into the annual operating planning and the strategic planning processes. The most significant enterprise-wide financial risks are identified during development of the annual operating plans, and are updated and presented monthly to the Finance Committee. Enterprise strategic risks are identified and presented to the Board during development of the five-year strategic plans. Following review and approval of the annual operating and strategic plans by the Board of Trustees and the Finance Committee, the Compensation Committee reviews the overall compensation program in the context of both plans. In particular, the Compensation Committee designs the annual and long-term incentive compensation programs for officers and eligible employees to promote the achievement of the goals and objectives of the annual operating plan and the strategic plan that were each previously subjected to ERM review.

In 2009, the Compensation Committee also assessed the risks associated with the executive compensation program proposed for the following year by specifically reviewing the various elements of the incentive compensation programs. The annual incentive program was reviewed to ensure an appropriate balance between the individual and corporate goals and that the goals were appropriate to support the annual business plan. Similarly, the long-term incentive program was reviewed to ensure that the performance metrics were properly weighted and supported the company s strategic plan. Both the annual and long-term incentive programs were reviewed to ensure that mechanisms exist to mitigate risk, which mechanisms include goal setting and discretion with respect to actual payments, share ownership guidelines, clawback of incentive compensation under certain circumstances, and deferral of certain long-term incentive awards.

ELEMENTS OF 2009 COMPENSATION

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

Compensation Element	Description	Objective
Base Salary	Fixed compensation	Compensate officers for fulfilling their basic job responsibilities
	Subject to increase 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 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 25% RSUs and 75% Performance Units (see below)	
· Restricted share units (RSUs)	Common share units, which vest over a three-year period, may be 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

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Performance units	Long-term incentive, two-thirds of which is performance cash and one-third of which is performance shares, that rewards individuals for corporate performance over a three-year period based on achieving pre-established levels of: · Cumulative net income · Average return on equity · Average credit rating · Total shareholder return relative to a group of comparable utility companies	Reward performance on key corporate priorities that are also key drivers of total shareholder return performance Align executive and shareholder interests through share performance and share ownership Strengthen the link between long-term compensation and total shareholder return performance Encourage long-term thinking and commitment to the company
Supplemental Benefits	Supplemental Executive Retirement Plan, Nonqualified Deferred Compensation, and Perquisites	Supplemental benefits intended to help us attract and retain executive officers critical to our 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 our standard defined benefit retirement plan, consisting of: · A defined benefit "make-whole" plan · A supplemental "target" benefit (certain senior vice presidents and	Compensate for Internal Revenue Code limits on qualified plans Aid in retention of executives and enhance long-term commitment to the company

above only)

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Executives hired after 2005 are ineligible for these benefits

Other Nonqualified Deferred Compensation (Deferral Plan)

Opportunity to defer base salary and annual incentives, using the same investment vehicles as NU s 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 our 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

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

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Perquisites

Tax preparation and financial planning reimbursement benefit

Executive physical examination reimbursement plan

Reimbursement of relocation expenses for newly hired and transferred executives

Reimbursement of spousal travel expenses only for business purposes

Encourage use of a professional tax advisor to properly prepare complex tax returns and leverage the value of our compensation programs

Encourage executives to undergo regular health checks to reduce the risk of losing critical employees

Discretionary benefits intended to help our executive officers be more productive and efficient

Employment Agreements

Employment or other agreements with certain of our Named Executive Officers provide benefits and payments upon involuntary termination and termination following a change of control. Mr. Olivier participates 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

We strive 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 our Named Executive Officers as described under the caption entitled "Market Analysis," below. As a result, the annual and long-term incentive target percentages for the NEOs listed in the Summary Compensation Table 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, with longer term goals, such as long-term value creation and maintaining a strong balance sheet. As our executive officers are promoted to more senior positions, they assume increased responsibility for implementing our long-term business plans and strategies, and a greater proportion of their total compensation is based on performance with a long-term focus.

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 for the daily operations and management of the Northeast Utilities System companies, as Chairman, President and Chief Executive Officer of NU and Chairman of each of the regulated companies, are significantly greater than the duties and responsibilities of our other executive officers. As a result, Mr. Shivery s compensation is significantly higher than the compensation of our other executive officers. NU regularly reviews market compensation data for executive officer positions similar to those held by our executive officers, including Mr. Shivery, and this market data continues to

indicate that chief executive officers are typically paid significantly more than other executive officers. For 2009, 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 100% to 150% of base salary.

The following table sets forth the contribution to 2009 Total Direct Compensation (TDC) of each element of compensation, at target, reflected as a percentage of TDC, for each Named Executive Officer.

		Percentage of TDC at Target			
		Performance Based (1)			
			Long-Term Incentives (2)		
Named Executive Officer	**Base Salary**	**Annual Incentive**	**Performance Units**	**RSUs (3)**	**TDC**
Leon J. Olivier, CEO, CL&P	32%	20%	36%	12%	100%
David R. McHale	32%	20%	36%	12%	100%
Charles W. Shivery	20%	20%	45%	15%	100%
Gregory B. Butler	32%	20%	36%	12%	100%
James B. Robb	40%	20%	30%	10%	100%

(1)

The annual incentive compensation element and performance units under the long-term incentive compensation element are performance-based.

(2)

Long-term incentive compensation at target consists of 75% performance units and 25% RSUs.

(3)

RSUs vest over three years contingent upon continued employment.

MARKET ANALYSIS

The Compensation Committee strives to provide our executive officers with compensation opportunities over time at or above the median compensation levels for executive officers of companies comparable to 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 primarily from utility and general industry surveys and, secondarily, from a customized group of peer utility companies. 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 our executive officers through a firm and direct connection between the compensation paid by us and the compensation paid by any of the companies in the utility and general industry surveys or in the customized group of peer utilities.

Set forth below is a description of the sources of the compensation data used by the Compensation Committee when reviewing 2009 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 our market for executive officer talent. The Committee used the utility and general industry survey data to determine base salaries and incentive opportunities. The compensation consultant reviewed subsets of survey data applicable to utility companies selected to reflect entities similar in size to NU. Then the Committee compared utility-specific executive officer positions, including NU s Executive Vice President and Chief Operating 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; Senior Vice President and General Counsel; and Senior Vice President-Enterprise Planning and Development, 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 our customized group of peer utility companies. Periodically, the Committee assesses the composition of our customized peer group to ensure that the number of companies is sufficient and the companies have reasonably similar revenues. The Committee most recently reviewed the composition of our customized peer group in 2009 and compared the group against NU s size guidelines of revenues between approximately $3 billion and $12 billion. Keeping in mind the Compensation Committee s desire 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 maintained the same peer group for 2009 that it used in 2008. As a result, in support of executive pay decisions during 2009, our customized peer group consisted of utilities with annual revenues that ranged from $1.7 billion to $14 billion with median annual revenues of $6.1 billion. However, revenues of three peer group companies from 2008 fell outside our revenue guidelines. NU will continue to monitor their size to determine if they should be removed from the peer group in the future. The Committee considered data only for those executive officer positions where there is a title match, which in 2009 included the holding company CEO, Chief Operating Officer, Chief Financial Officer, and General Counsel. For 2009, the peer group consisted of the following 20 companies:

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Allegheny Energy, Inc.	Great Plains Energy, Incorporated	Pinnacle West Capital Corporation
Alliant Energy Corporation	Integrys Energy Group, Inc.	Progress Energy, Inc.
Ameren Corporation	NiSource Inc.	SCANA Corporation
CenterPoint Energy, Inc.	NSTAR	TECO Energy, Inc.
CMS Energy Corporation	NV Energy, Inc.	Wisconsin Energy Corporation
Consolidated Edison, Inc.	OGE Energy Corp.	Xcel Energy Inc.
DTE Energy Company	Pepco Holdings, 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 2009 directly as a result of this information. In 2009, the Committee also used this group for performance comparisons under the 2009 2011 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 our supplemental retirement practices most recently in 2005 and 2006, as described in more detail below under the caption entitled "Supplemental Benefits."

BASE SALARY

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

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Annual individual performance appraisals

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Market pay movement across industries (determined through market analysis)

- Targeted market pay positioning for each executive officer
- Individual experience and years of service
- Changes in corporate focus with respect to strategic importance of a position
- Internal equity

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

In 2009, given the continuing uncertainty in the capital markets and weakened economic conditions, it was determined to freeze the base salaries of executive officers, including the NEOs.

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 its 2007 Annual Meeting of Shareholders. The annual incentive program provides cash compensation intended to reward performance under our annual operating plans. The long-term incentive program is designed to reward demonstrated performance and leadership, motivate future superior performance, align the interests of the executive officers with those of our shareholders and retain the executive officers during the term of grants. The annual and long-term programs are intended to work in tandem so that achievement of our annual goals leads us towards attainment of our long-term financial goals. Beginning in 2009, grants under the long-term incentive program consist of three elements of compensation: RSUs, performance cash, and performance shares. Prior to 2009, RSUs served as the only equity component of long-term grants, primarily because utility companies create value for shareholders through the payment of periodic dividends as well as through share price appreciation. Effective with the 2009 2011 Long-Term Incentive Program, performance shares were introduced as a second equity component of long-term grants to strengthen the connection between performance and compensation.

Incentive grants 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 our business focus for the then-current year and the long-term strategic plan.

2009 ANNUAL INCENTIVE PROGRAM

The 2009 Annual Incentive Program consisted of a corporate goal plus individual goals for each NEO. The Compensation Committee set the annual incentive compensation targets for 2009 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. A total of 29 NU system company officers, including CL&P s NEOs, participated in the 2009 Annual Incentive Program.

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

2009 Corporate Goal

The objective of the 2009 Annual Incentive Program corporate goal for the NEOs was to achieve an adjusted net income (ANI) target established by the Compensation Committee. ANI is defined as consolidated Northeast Utilities 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 110% of the ANI target.

For 2009, the Compensation Committee established the ANI target at $303.6 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)	2009 ANI Target	Maximum Corporate Goal (10% above ANI Target)	Actual 2009 ANI
$242.9	$273.2	$303.6	$334.0	$329.5

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 2009, 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. In addition, using its discretion, the Compensation Committee excluded the positive effect on earnings that would have resulted from the delay of a planned asset transaction. The income and expense items set forth below were excluded from ANI in 2009.

Excluded Categories	**Specific 2009 Adjustments ($ in millions)**
Unexpected costs related to environmental remediation at HWP Company (formerly Holyoke Water Power Company)	0.7
Delay in planned asset transactions	(1.2)
Net Adjustments:	$(0.5)

2009 Individual Goals

The 2009 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. Upon achieving this ANI threshold, the maximum payout is possible for individual goals for every participant.

This 80% ANI threshold satisfies the requirements of Section 162(m) of the Internal Revenue Code. 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 NU s 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 NU s 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 and Individual Goals for 2009

The following table sets forth the weighting of the annual incentive program corporate goal and individual goals of each NEO s compensation for 2009. These weightings reflect the Compensation Committee s desire to balance individual accountability with teamwork across NU s organization. Individual goals range from 40% to 50% of the total annual incentive program target. Certain of our NEOs 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 the Board, President, and Chief Executive Officer of NU, Chairman of CL&P	60%	40%	Ensure effective execution of NU s strategic plan and the 2009 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 2009 through the appropriate alignment of strategy, organizational structure, compensation design, resources and culture. Define NU s vision with respect to the federal economic stimulus package, energy policy, and demands of customers for products and services to manage their energy needs; implement strategies consistent with that vision. (25% of individual goals).
			Shape the 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).
			Develop and implement a strategy for embedding sustainability into the company s operations and relationships with its key stakeholders. Achieve improvements in NU s reputation among its various stakeholders (10% of individual goals).
			Continue to execute our strategy that brings a customer focus to the forefront of the organization; communicate expectations and standards around the customer s experience (10% of individual goals).
			Continue to implement cultural changes required for NU to succeed in an evolving environment. Make measurable improvements in safety-related results. Lead through tone and actions NU s efforts to realize its vision to create an inclusive environment and a diverse workforce (10% of individual goals).
David R. McHale Executive Vice President and Chief Financial Officer	60%	40%	Successfully execute operating plans: support NU s strategy, 2009 operating plan, and competitive businesses, and improve effectiveness of shared services (40% of individual goals).
			Achieve strategic initiatives: position NU to achieve new opportunities and finance growth while ensuring integrity of NU s financial position (20% of individual goals).
			Manage department expenditures; continue to execute internal customer focus strategy (15% of individual goals).
			Effectively communicate NU s strategy and financial position to stakeholders (15% of individual goals).
			Achieve organization development goals: complete new financial and shared services organizations; manage for an

			inclusive environment and diverse workforce (10% of individual goals).
Gregory B. Butler Senior Vice President and General Counsel	50%	50%	Manage Legal Department to enable NU to achieve its strategic plan and 2009 operating and capital financing objectives; provide leadership with respect to uncollectibles expense and HWP Company site remediation (30% of individual goals).
			Influence, support and provide expertise for NU s strategic initiatives and emerging opportunities (30% of individual goals).
			Achieve successful outcomes in federal and state energy regulatory legislative proceedings; help position the company as a leading expert on energy issues (25% of individual goals).
			Provide quality internal customer support; execute talent management and development plans; manage budget (15% of individual goals).
James B. Robb Senior Vice President Enterprise Planning and Development of NUSCO	50%	50%	Develop plan for embedding sustainability into NU s decision-making and continue to build on NU s emerging reputation as thought leaders on energy issues (45% of individual goals).
			Develop comprehensive energy productivity and renewable generation strategies; support development of northern transmission opportunities (35% of individual goals).
			Articulate NU s energy policy positions, lead NU s response on federal energy policy issues and development of federal stimulus projects (20% of individual goals).

2009 Results

The 2009 actual ANI was $329.5 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 the corporate goal at 185% of target. In addition, the 2009 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 individual goals.

Mr. Shivery s Annual Incentive Payment

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

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Mr. Shivery s execution of NU s long-term strategic plan as well as its 2009 operating and capital plans was above expectations. NU achieved successful outcomes in various legislative and regulatory proceedings, including temporary rate relief at Public Service Company of New Hampshire and an order from the Federal Energy Regulatory Commission authorizing NU to proceed in partnership with NSTAR with the Hydro-Québec transmission project. This visionary long-term project will deliver low-carbon power to New England over a new transmission line between northern New England and Hydro-Québec in eastern Canada.

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With Mr. Shivery s leadership, Northeast Utilities continued to remain financially strong in the face of extreme disruptions in the financial markets and a severe economic recession. Implementation of NU s $6 billion capital investment program is on track and has yielded increased earnings and improved reliability.

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NU launched its first comprehensive sustainability report showcasing its commitment to environmental stewardship and corporate responsibility. NU continued to position itself as a leader in smart grid related initiatives and in developing a regional electric vehicle strategy. On balance, Mr. Shivery s performance regarding customer focus and workforce development met expectations.

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 $1,645,650 for 2009, consisting of $1,148,850 attributable to the achievement of 185% of the corporate goal and an additional $496,800 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 2009. Mr. Shivery s annual incentive payment exceeds that of the other NEOs because of his significantly greater duties and responsibilities as NU s CEO.

NEO Annual Incentive Payments

In addition to the 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 2009.

The Compensation Committee determined that Mr. McHale and his organization successfully issued significant debt and common equity on favorable terms, maintaining and enhancing liquidity through a period of economic contraction. Mr. McHale and his team also achieved significantly higher than expected margins from NU s competitive businesses and provided critical subject matter expertise on a number of strategic fronts, including financial, analytical and risk management support for NU s major strategic initiatives. Based on his demonstrated leadership and this assessment of his successes, the Compensation Committee awarded Mr. McHale an annual incentive payment of $555,728 for 2009.

The Compensation Committee determined that Mr. Olivier and his team effectively executed NU s operating plan and the 2009 components of NU s five-year strategic plan while managing in a resource-constrained environment in response to the very challenging economy. Accomplishments included attainment of milestones related to the Massachusetts Green Communities Act Solar Energy Plan, Yankee Gas expansion, major transmission projects including the Hydro-Québec transmission project, the New Hampshire Merrimac scrubber, and effective completion of the year s capital program. Based on his demonstrated leadership and the Committee s assessment of his accomplishments, the Committee awarded Mr. Olivier an annual incentive payment of $558,415 for 2009.

The Compensation Committee determined that Mr. Butler s team advanced NU s position on regional energy policies 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 Hydro-Québec transmission project 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 the regulated companies as each of them executed their operating plans. Based upon these results, the Compensation Committee awarded Mr. Butler an annual incentive payment of $414,009 for 2009.

The Compensation Committee determined that Mr. Robb and his team were instrumental in the progress on NU s Hydro-Québec transmission project, including obtaining authorization from the Federal Energy Regulatory Commission for NU to proceed with the project, and in positioning NU as a leader in smart grid and electric vehicle strategies. Based upon these successes and his demonstrated leadership within NU and NU s community, the Compensation Committee awarded Mr. Robb an annual incentive payment of $316,500 for 2009.

LONG-TERM INCENTIVE PROGRAMS

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 presented 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. Beginning with the 2009 2011 Long-Term Incentive Program, at target, each grant generally consisted of 25% RSUs and 75% performance units (two-thirds of which were performance cash and one-third of which were performance shares), 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 the roles of total shareholder return and NU s corporate financial performance in our compensation programs.

For the 2009 2011 program, 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 100% to 150% of base salary for the remaining NEOs.

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 2009 will vest in equal annual installments over three years. RSU holders are eligible to receive reinvested dividend units on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU common shares. Reinvested dividend units are accounted for as additional RSUs that accrue and are distributed with the common shares issued upon vesting and distribution of the underlying RSUs. Common shares, including any additional common shares in respect of reinvested dividend units, are not issued for any RSUs that do not vest.

General

Annually, the Compensation Committee determines RSU grants for each officer participating in the long-term incentive program. Initially, the target RSU grants are equal to 25% of the long-term incentive compensation target for each officer. RSU grants are based on a percentage of base salary and measured in dollars. The percentage used for each officer is based on the officer s position in the company and ranges from 9% to 75% of salary. The Committee reserves the right to increase or decrease the RSU grant from target for each officer under special circumstances. 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 officers, including the other NEOs. Increases or decreases to target RSU grants for our officers will increase or decrease their compensation as compared to the compensation of officers of utilities listed in our customized peer group.

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 value of each grant by the average closing price for NU common shares during the last ten trading days in January in the year of the grant.

RSU Grants under the 2009 2011 Program

Under the 2009 2011 program, the target RSU grant totaled approximately $2.4 million for all 30 officers participating in the long-term incentive program. The Committee did not adjust any officer s RSU grant from target for the 2009 2011 program. Accordingly, the final total RSU grant for officers, including Mr. Shivery, was unchanged from target. Dividing the final total RSU grant by $23.74, the average closing price for NU common shares during the last ten trading days in January 2009, resulted in an aggregate of 100,157 RSUs. The following RSU grants at 100% of target were approved, reflected in RSUs: Mr. Shivery: 32,702; Mr. McHale: 8,294; Mr. Olivier: 8,689; Mr. Butler: 6,430; and Mr. Robb: 4,213.

Performance Units

General

Performance Units are a performance-based component of our long-term incentive program. A new three-year program commences every year. Performance unit grants are equal to 75% of total individual long-term incentive grants at target. Two-thirds of the performance unit grant in the 2009 2011 program consists of a performance cash grant and the remaining one-third of each performance unit grant consists of a performance share grant. Consequently, performance cash grants are equal to 50% of the total individual long-term incentive grants at target, and performance share grants are equal to 25% of the total individual long-term incentive grants at target. Both performance cash grants and performance share grants are measured in dollars. Performance share grants are subsequently converted from dollars into NU common share equivalents by dividing the value of each grant by the average closing price for NU common shares during the last ten trading days in January in the year of the grant. During the three-year performance program period, the dividends that would have been paid with respect to the performance shares to holders of performance share grants are accounted for as additional common shares that accrue and are distributed with the common shares, if any, at the end of the program. Prior to the 2009 2011 program, the performance unit grants consisted solely of performance cash.

Awards under a program are earned to 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 awards, 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 are 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 Northeast Utilities (excluding the regulated companies), 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, or "points," 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 large point value represents a high credit rating. In addition to average credit rating objectives, the ratings of Northeast Utilities by S&P and Moody s must remain above investment grade.

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Relative total shareholder return of Northeast Utilities as compared to the return of the utility companies listed in the performance peer group identified for each long term incentive program.

The selection of these four metrics reflects the Compensation Committee s belief that these areas are critical measurements of corporate success. For the 2009 2011 program, the Committee weighted each of the four metrics equally. The Committee measures performance against 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 performance against 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. Before any amount is payable with respect to a metric, NU must achieve a minimum level of performance under that metric. If NU achieves the minimum level of performance for any goal, then the resulting payout will equal 50% of the target for that goal. If NU achieves the maximum level of performance for any goal, then the resulting payout will equal 150% of target for that goal. 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.

Set forth below are descriptions of each of the three long-term performance programs that were in effect during 2009. The peer groups used by the Committee for performance comparisons under each program are listed in footnote 1 to the table that accompanies each description. 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. Prior to the 2009 2011 program, the customized peer group had 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 evaluates the total shareholder return metric using the same customized group of peer utilities described above under "Market Analysis."

2007 2009 Performance Cash

The Compensation Committee approved the 2007 2009 performance cash grants in early 2007. Upon completion of NU s fiscal year ended December 31, 2009, 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 109% of target.

The 2007 2009 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 2007 2009 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:

Excluded Categories	**Specific 2009 Adjustments ($ in millions)**
Changes to net income as the result of accounting or tax law changes	$ 31.2
Unexpected costs related to nuclear decommissioning	(1.4)
Unexpected costs related to environmental remediation at HWP (formerly Holyoke Water Power Company)	2.4
NU Enterprises, Inc. mark-to-market impact	(4.2)
Unbudgeted charitable contributions	1.9
Changes to net income resulting from any settlement of, or final decision in, ongoing litigation with Consolidated Edison	25.8
Divestiture or discontinuance of a segment or component of NU s business	2.4
Discretionary adjustment by Compensation Committee due to delayed in-service date of customer service system	(6.4)
Net Adjustments:	$(51.7)

The table set forth below describes the goals under the 2007 2009 program and NU s actual results during that period:

	2007 2009 Program Goals			
Goal	**Minimum**	**Target**	**Maximum**	**Actual Results**
Cumulative Adjusted Net Income ($ in millions)	$753.2	$836.9	$920.6	$889.0
Average Adjusted ROE	8.4%	9.2%	10.0%	9.5%
Average Credit Rating Points	1.2	1.7	2.2	1.7
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th	54th

(1)

The performance peer group for the 2007 2009 program includes Northeast Utilities 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.

Based on NU s financial performance during the three-year performance period of the 2007 2009 Long-Term Incentive Program, the Committee approved the following performance cash awards: Mr. Shivery: $1,635,000; Mr. McHale: $367,875; Mr. Olivier: $323,594; and Mr. Butler: $316,870. Mr. Robb did not participate in this program. The payments were determined pursuant to formulas set forth in the 2007 2009 Long-Term Incentive Program and were not subject to the discretion of the Compensation Committee.

2008 2010 Performance Cash

The Committee approved the 2008 2010 performance cash goals in early 2008. No awards have been paid under this program, and the Committee will not determine whether any awards are payable until the end of our 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 HWP Company; 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 the 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 Points	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 Northeast Utilities 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 2011 Performance Units

The Committee approved the 2009 2011 performance unit goals in early 2009. No awards have been paid under this program, and the Committee will not determine whether any awards are payable until the end of our 2011 fiscal year, which is the final year in the three-year program.

As described above, under the 2009 2011 program, two-thirds of each performance unit grant consists of a performance cash grant and the remaining one-third of each performance unit grant consists of a performance share grant. The 2009 2011 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 2009 2011 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 HWP Company; 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; and impairments on goodwill acquired before 2003 (more than six years prior to the beginning of this program cycle).

The table set forth below describes the goals under the 2009 2011 program:

	2009 2011 Program Goals		
Goal	**Minimum**	**Target**	**Maximum**
Cumulative Adjusted Net Income ($ in millions)	$899.3	$999.2	$1,099.1
Average Adjusted ROE	8.4%	9.3%	10.1%
Average Credit Rating Points	1.2	1.7	2.2
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th

(1)

The performance peer group for the 2009 2011 program includes Northeast Utilities and the following companies: Allegheny Energy, Inc., Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., CMS Energy Corporation, Consolidated Edison, Inc., DTE Energy Company, Great Plains Energy Incorporated, Integrys Energy

Group Inc., NiSource Inc., NSTAR, NV Energy, Inc., OGE Energy Corp., Pepco Holdings, Inc., Pinnacle West Capital Corporation, Progress Energy Inc., SCANA Corporation, TECO Energy, Inc., Wisconsin Energy Corporation and Xcel Energy Inc.

2010 CHANGES

2010 2012 Long-Term Incentive Program

In late-2009, the Compensation Committee changed the performance elements of the 2010 2012 Long-Term Incentive Program by shifting a portion of performance cash to performance shares to further strengthen the alignment of the performance elements with NU s shareholders. For the 2010 2012 program, the grant value at target will consist of 37.5% performance shares and 37.5% performance cash. RSUs will constitute 25% of the grant value at target, unchanged from the 2009 2011 program.

Also in late-2009, the Compensation Committee changed the weighting of the four metrics used to determine payments under the 2010 2012 Long-Term Incentive Program to further emphasize to participants the importance of achieving a relative total shareholder return that exceeds the median peer group performance and to better align the long-term interests of participants and NU s shareholders consistent with the long-term objectives of the company to build and sustain value. Previously, the four metrics, consisting of cumulative adjusted net income, average adjusted ROE, average credit rating, and relative total shareholder return, were equally weighted. Commencing with the 2010 2012 program, , the relative total shareholder return goal will account for 40% of the performance units granted, while the cumulative adjusted net income, average adjusted ROE, and average credit rating metrics will each account for 20% of the performance units granted.

SHARE OWNERSHIP GUIDELINES

Effective in 2006, the Compensation Committee approved share ownership guidelines to emphasize the importance of share ownership by certain of NU s executive officers. The Committee most recently reviewed the guidelines for these executive officers in 2009 and determined that they remain reasonable and require no modification. The guidelines call for Mr. Shivery to own 200,000 shares, which is currently valued at approximately five- to six-times base salary, and the other executive officers to own a minimum number of common shares valued at approximately two- to three-times base salary.

Executive Officer	Ownership Guidelines (Number of Shares)	Approximate Salary Multiple
Mr. Shivery	200,000	5-6
EVPs/SVPs	30,000 45,000	2-3

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 our NEOs are currently at, or close to, the share ownership guidelines except for Mr. Robb, who commenced employment with NU in 2007. Common shares, whether held of record, in street name, or in individual 401(k) accounts, and RSUs satisfy the guidelines. Unexercised stock options do not count toward the ownership guidelines.

HEDGING PRACTICES

NU does not allow any NEO to enter into any derivative transaction on NU common shares, including any short-sales, forward-sales, options and collars.

SUPPLEMENTAL BENEFITS

We provide a variety of basic and supplemental benefits designed to assist us 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. We do not provide permanent lodging or personal entertainment for any executive officer or employee, and our executive officers are eligible to participate in substantially the same health care and benefit programs available to our employees.

RETIREMENT BENEFITS

We provide 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 Mr. Robb and other 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.

For NEOs who participate in the Retirement Plan, 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. Robb. 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 our 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.

401K PLAN

We provide 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 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. Mr. Robb and other 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

Our executive officers participate in the Deferral Plan to provide additional retirement benefits not available in our 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 s 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 our philosophy that perquisites should be provided to executive officers only as needed for business reasons, and not simply in reaction to prevalent market practices.

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

All executive officers receive a special annual physical examination benefit to help ensure serious health issues are detected early. The benefit is limited to the reimbursement of up to $800 for fees incurred beyond those covered by our medical plan.

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When hiring a new executive officer or transferring an executive officer to a new location, we sometimes reimburse executive officers for reasonable temporary living and relocation expenses, or provide a lump sum payment in lieu of specific reimbursement. These expenses are grossed-up for income taxes attributable to such reimbursements so that relocation or transfer 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 we will reimburse the executive officer for all spousal travel expenses.

Effective beginning in 2009, we 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 and other agreements with certain executive officers, including the NEOs. The agreements specify all or part of the following: compensation and benefits during the employment term, benefits payable upon involuntary termination of employment, and benefits payable upon 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. We continue to believe that these benefits help to ensure our 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, Butler and Robb provide for enhanced cash severance benefits following termination of employment without "cause" (as defined in the employment agreement, generally involving a felony conviction; acts of fraud, embezzlement, or theft in the course of employment; intentional, wrongful damage to NU property; gross misconduct or gross negligence in the course of employment; or a material breach of obligations under the agreement) or upon termination of employment by the executive for "good reason" (as defined in the employment agreement, generally meaning an assignment to duties inconsistent with his position, a failure by the employer to satisfy material terms of the agreement or the transfer of the executive to an office location more than 50 miles from his or her principal place of business immediately prior to a change of control). The Compensation Committee believes that termination for good reason is conceptually 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 participates instead in the Special Severance Program.

For Messrs. Shivery, McHale and Butler, a "change of control" is defined in their employment agreements as a change in ownership or control effected through (i) the acquisition of 20% or more of the combined voting power of common shares or other voting securities, (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 Northeast Utilities, or a sale or disposition of all or substantially all of the assets of Northeast Utilities 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. For Mr. Robb, a "change of control" is as defined in the shareholder-approved Northeast Utilities Incentive Plan.

Pursuant to the change of control provisions in the employment agreements, each NEO except for Mr. Olivier and Mr. Robb would 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. Robb 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 us after the termination of an executive officer s employment, the employment agreements include non-competition and non-solicitation covenants pursuant to which the executive officers have agreed not to compete with NU system companies or solicit NU companies employees for a period of two years (one year for Mr. Olivier pursuant to the Special Severance Program and one year for Mr. Robb pursuant to his agreement) after termination of employment.

In the event of termination of employment without "cause" or upon termination of employment by an NEO for good reason, in each case following a change of control, the expiration date of all vested unexercised stock options held by our NEOs would 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 would be paid according to the schedule defined by the executive s original election.

As discussed under the caption entitled "Supplemental Benefits," above, the 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 2009 was fully deductible for federal income tax purposes, except for approximately $81,000 paid to Mr. Shivery, consisting of RSU distributions of approximately $68,000 and salary and reimbursements of approximately $13,000.

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. Our annual incentive program and performance unit grants 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, 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 NU s employment, at which time Section 162(m) will no longer apply to him. The non-deductible RSU distributions for Mr. Shivery in 2009 described above relate to RSUs granted before Mr. Shivery was elected as NU s CEO.

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 our 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, our NEOs are entitled to receive certain payments upon termination of their employment, including termination following a change of control. Under the terms of the agreements, all NEOs except Mr. Olivier and Mr. Robb are entitled to receive tax gross-ups for any payments that constitute an excess parachute payment. Accordingly, a 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 entitled "Potential Payments at Termination or Change of Control," below.

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

Accounting Considerations. RSUs and performance shares disclosed in the Grants of Plan-Based Awards Table are accounted for based on their grant date fair value, as determined under FASB ASC Topic 718, which is recognized over the service period, or the three-year vesting period applicable to the grant. Assumptions used in the calculation of this amount appear under the caption entitled *Management s Discussion and Analysis and Results of Operations* in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009. Forfeitures are estimated, and the compensation cost of the grants will be reversed if the employee does not remain employed by us throughout the three-year vesting period. Performance unit grants 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 CL&P s 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 behalf for the fiscal year ended December 31, 2009. 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, including CL&P, 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 ($) (7)	Total ($)
Charles W. Shivery	2009	1,035,000		1,574,915		3,280,650	1,812,023	31,050	7,773,638
	2008	1,067,404		1,891,430		3,257,929	1,627,493	35,397	7,879,653
Chairman of the Board, President and CEO of NU; Chairman of CL&P	2007	987,308		2,754,632		3,048,360	1,326,931	49,026	8,166,257
David R. McHale	2009	524,520		399,436		923,603	1,038,268	7,350	2,893,177
	2008	508,654		456,858		750,214	514,753	9,907	2,240,386
Executive Vice President and Chief Financial Officer (8)	2007	434,135		531,240		755,810	614,481	7,603	2,343,269
Leon J. Olivier	2009	550,000		418,459		882,009	219,565	16,500	2,086,533
Executive Vice President and	2008	550,962		407,367		839,571	324,854	18,997	2,141,751
Chief Operating Officer of NU; CEO of CL&P	2007	462,096		467,313		777,226	251,556	15,042	1,973,233
Gregory B. Butler	2009	406,988		309,666		730,878	503,614	7,350	1,958,496
	2008	418,542		327,261		723,674	206,850	8,207	1,684,534
Senior Vice President and General Counsel	2007	382,244		396,595		731,950	195,321	12,941	1,719,051

James B. Robb Senior Vice President Enterprise Planning & Development of NUSCO	2009	400,000		202,896		316,500		23,025	942,422

(1)

Includes amounts deferred in 2009 by the Named Executive Officers under the Deferral Plan, as follows: Mr. Shivery: $31,050; Mr. Olivier: $137,500; and Mr. Robb: $8,000. 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. One additional pay date occurred in 2008. 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 2009 and 2007.

(2)

No discretionary bonus awards were made to any of the Named Executive Officers in the fiscal years ended 2007, 2008 and 2009.

(3)

Reflects the aggregate grant date fair value of restricted share units (RSUs) and performance shares granted in each fiscal year, calculated in accordance with FASB ASC Topic 718.

In 2007, 2008 and 2009, certain Named Executive Officers were granted RSUs that vest in equal annual installments over three years as long-term incentive compensation. NU deferred 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 equivalent units on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU s common shares. Dividend equivalent units 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 2009, the Named Executive Officers were granted performance shares as long-term compensation. These performance shares will vest on December 31, 2011, based on the extent to which four performance conditions are achieved. The grant date values for the performance shares, assuming achievement of the highest level of all four performance conditions, are as follows: Mr. Shivery: $1,187,063; Mr. McHale: $301,067; Mr. Olivier: $315,406; Mr. Butler: $233,405; and Mr. Robb: $152,929.

(4)

NU has not granted any stock options since 2002. Accordingly, we did not grant stock options to any of the Named Executive Officers in 2009.

(5)

Includes payments to the Named Executive Officers under the 2009 Annual Incentive Program (Mr. Shivery: $1,645,650; Mr. McHale: $555,728; Mr. Olivier: $558,415; Mr. Butler: $414,009; and Mr. Robb: $316,500) Also includes performance cash payments under the 2007 2009 Long-Term Incentive Program (Mr. Shivery: $1,635,000; Mr. McHale: $367,875; Mr. Olivier: $323,594; and Mr. Butler: $316,870). Performance goals under the 2009 Annual Incentive Program were communicated to each officer by Mr. Shivery or, in the case of Mr. Shivery, jointly by NU s Compensation Committee and Corporate Governance Committee of the Board of Trustees, during the first 90 days of 2009. 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 2010. Performance goals under the 2007 2009 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 2007. The Compensation Committee determined the extent to which the long-term goals were satisfied in February 2010.

(6)

Includes the actuarial increase in the present value from December 31, 2008 to December 31, 2009 of the Named Executive Officer s accumulated benefits under all of our defined benefit pension plans determined using interest rate and mortality rate assumptions consistent with those appearing in Item 7 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. Mr. Robb does not participate in a plan that provides pension benefits. There were no above-market earnings on deferrals in 2009.

(7)

Includes matching contributions of $7,350 allocated to the account of each of the Named Executive Officers under the 401k Plan; plus nonqualified K-Vantage Contributions under the 401k Plan (Mr. Robb: $11,025); and employer matching contributions under the Deferral Plan for the NEOs who deferred part of their salary in the fiscal year ended

December 31, 2009 (Mr. Shivery: $23,700; Mr. Olivier: $9,150; and Mr. Robb: $4,650). Mr. McHale and Mr. Butler did not participate in the Deferral Plan in 2009.

(8)

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

GRANTS OF PLAN-BASED AWARDS DURING 2009

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, 2009. 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, we did not grant stock options to any of the Named Executive Officers in 2009.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Option Awards
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**(#) (3)**	**($) (4)**
Charles W. Shivery						
Annual Incentive (1)	2/10/2009	517,500	1,035,000	2,070,000	--	--
Long-Term Incentive (2)	2/10/2009	776,250	1,552,500	2,328,750	65,404	1,574,915
David R. McHale						
Annual Incentive (1)	2/10/2009	170,625	341,250	682,500	--	--
Long-Term Incentive (2)	2/10/2009	196,875	393,750	590,625	16,588	399,436
Leon J. Olivier						
Annual Incentive (1)	2/10/2009	178,750	357,500	715,000	--	--
Long-Term Incentive (2)	2/10/2009	206,250	412,500	618,750	17,378	418,459
Gregory B. Butler						
Annual Incentive (1)	2/10/2009	132,271	264,542	529,084	--	--
Long-Term Incentive (2)	2/10/2009	152,621	305,241	457,862	12,860	309,666
James B. Robb						
Annual Incentive (1)	2/10/2009	100,000	200,000	400,000	--	--
Long-Term Incentive (2)	2/10/2009	100,000	200,000	300,000	8,426	202,896

(1)

Amounts reflect the range of potential payouts, if any, under the 2009 Annual Incentive Program for each Named Executive Officer, as described in the Compensation Discussion and Analysis. The payment in 2010 for performance in 2009 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 2009 2011 Long-Term Incentive Program, as described in the Compensation Discussion and Analysis. Grants of three-year performance cash awards were made in 2009 under the 2009 2011 Long-Term Incentive Program. Performance cash will be fully vested at the end of the performance period and paid to the officers in cash during the first fiscal quarter after the end of the performance period.

(3)

Reflects the number of RSUs and performance shares granted to each of the Named Executive Officers on February 10, 2009 under the 2009 2011 Long-Term Incentive Program. Performance shares were granted with a three-year Performance Period that ends on December 31, 2011. At the end of the Performance Period, common shares will be awarded based on performance compared to goals, subject to reduction for applicable withholding taxes. RSUs vest in equal installments on February 25, 2010, 2011 and 2012. Except for Messrs. Shivery and Robb, 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 of vested RSUs in three approximately equal annual installments beginning the later of (i) six months after he leaves NU s employment and (ii) January of the calendar year after he leaves NU s employment. For Mr. Robb, NU will distribute common shares after reduction for applicable withholding taxes, in respect of vested RSUs beginning the earlier of (i) sixteen years beyond the vesting date or (ii) six months after he leaves NU s employment. Holders of RSUs and performance shares are eligible to receive dividend equivalent units on outstanding RSUs and performance shares held by them to the same extent that dividends are declared and paid on NU s common shares. Dividend equivalent units are accounted for as additional common shares that accrue and are distributed simultaneously with the common shares distributed in respect of the underlying RSUs or performance shares. The Annual Incentive Program does not include an equity component.

(4)

Reflects the grant-date fair value of RSUs and performance shares granted to the Named Executive Officers on February 10, 2009, under the 2009 2011 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, 2009

The following table sets forth option and RSU grants outstanding at the end of our fiscal year ended December 31, 2009 for each of the Named Executive Officers. All outstanding options were fully vested as of December 31, 2009.

	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	06/11/2012	118,181	3,047,882
David R. McHale	--	--	--	27,249	702,744
Leon J. Olivier	--	--	--	25,563	659,264
Gregory B. Butler	--	--	--	20,233	521,797
James B. Robb	--	--	--	12,388	319,476

(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 116,669 unvested RSUs vested on February 25, 2010 (Mr. Shivery: 70,958; Mr. McHale: 15,568; Mr. Olivier: 14,249; Mr. Butler: 11,526; and Mr. Robb: 4,368). An additional 2,188 unvested RSUs will vest on September 4, 2010 (Mr. Robb). An additional 63,810 unvested RSUs will vest on February 25, 2011 (Mr. Shivery: 35,870; Mr. McHale: 8,801; Mr. Olivier: 8,297; Mr. Butler: 6,474 and Mr. Robb: 4,368). An additional 20,943 unvested RSUs will vest on February 25, 2012 (Mr. Shivery: 11,353; Mr. McHale: 2,879 Mr. Olivier: 3,016 Mr. Butler: 2,232 and Mr. Robb: 1,463).

(4)

The market value of RSUs is determined by multiplying the number of RSUs by $25.79, the closing price per share of common shares on December 31, 2009, the last trading day of the fiscal year.

OPTIONS EXERCISED AND STOCK VESTED IN 2009

The following table reports amounts realized on equity compensation during the fiscal year ended December 31, 2009. None of the Named Executive Officers exercised options in 2009. The Stock Awards columns report the vesting of RSU grants to the Named Executive Officers in 2009.

	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	--	--	86,056	1,927,665
David R. McHale	--	--	16,902	378,596
Leon J. Olivier	--	--	15,361	344,089
Gregory B. Butler	--	--	13,728	307,500
James B. Robb	--	--	4,916	112,788

(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 RSUs granted to our Named Executive Officers under our long-term incentive programs, including dividend reinvestments, as follows:

Name	2006 Program	2007 Program	2008 Program
Charles W. Shivery	28,826	33,690	23,541
David R. McHale	4,718	6,497	5,686
Leon J. Olivier	4,576	5,715	5,070
Gregory B. Butler	4,804	4,850	4,073
James B. Robb	--	2,125	2,790

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 on vesting of Mr. Robb s 2007 RSU grant is based on $23.66 per share, the closing price of common shares on September 3, 2009. Value realized on vesting for all other amounts is based on $22.40 per share, the closing price of common shares on February 24, 2009. This value includes the value of vested RSUs for which the distribution of common shares is currently deferred.

PENSION BENEFITS IN 2009

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 retirement as of the first date upon which he is eligible to receive an unreduced pension benefit (see below). The table distinguishes the benefits among those available through the Retirement Plan, the Supplemental Plan and any additional benefits available under the respective officer s employment agreement. The Supplemental Plan provides a make whole benefit that is based in part on compensation that is not permitted to be recognized under a tax-qualified plan and provides a target benefit if the eligible officer continues his 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 and Butler (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, 2009 assuming benefits would be paid in the form of a one-half 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). 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, and Mr. Butler is eligible to receive unreduced benefits at age 62. Mr. Robb does not participate in the Retirement Plan nor the Supplemental Plan.

The limitations applicable to the Retirement Plan under the Internal Revenue Code as of December 31, 2009 were used to determine the benefits under each plan. The accrued benefits reflect actual compensation (both salary and incentives) earned during 2009. 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 2010 payment pursuant to the 2009 Annual Incentive Program was reflected in the 2009 plan compensation. We determined the present value of the benefit at retirement age by using the discount rate of 5.98% under Statement of Financial Accounting Standards No. 87 for the 2009 fiscal year end measurement (as of December 31, 2009). This present value assumes no pre-retirement mortality, turnover or disability. However, for the postretirement period beginning at the retirement age, we used the RP2000 Combined Healthy mortality table as published by the Society of Actuaries projected to 2010 with projection scale AA (same table used for financial reporting under FAS 87). Additional assumptions appear in Item 7 *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)	Retirement Plan	7.6	265,667	--
	Supplemental Plan	7.6	5,295,389	--
	Other Special Benefit	10.6	2,200,220	--
David R. McHale	Retirement Plan	28.3	576,214	--
	Supplemental Plan	28.3	2,762,825	--
Leon J. Olivier (2)	Retirement Plan	10.8	373,692	--
	Supplemental Plan	8.3	--	--
	Other Special Benefit	8.3	1,820,601	--
	Other Special Benefit	31.3	1,280,779	105,966
Gregory B. Butler	Retirement Plan	13.0	269,241	--
	Supplemental Plan	13.0	1,435,036	--
James B. Robb	Retirement Plan	--	--	--
	Supplemental Plan	--	--	--

(1)

Mr. Shivery s actual service with NU totaled 7.6 years at December 31, 2009. 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, 2009 was approximately $2,200,220.

(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 NU until September 10, 2011 (or terminates his employment earlier with NU s consent), he will be eligible to receive a special benefit, subject to reduction for termination prior to age 65, consisting of three percent of final average compensation for each of his first 15 years of service since September 10, 2001, plus one percent of final average compensation for each of the second 15 years of service. Alternatively, if Mr. Olivier voluntarily terminates his employment with NU after his 60th birthday, or NU terminates his employment earlier for any reason other than "cause" (as defined in his employment agreement, generally meaning willful and continued failure to perform his duties after written notice, a violation of NU s Standards of Business Conduct or conviction of a felony) he is eligible to receive upon retirement a lump sum payment of $2,050,000 in lieu of benefits under the Supplemental Plan and the benefit described in the preceding sentence. These supplemental pension benefits will be offset by the value of any benefits he receives from the Retirement Plan. Because Mr. Olivier attained age 60 during 2008, amounts reported in the table assume the termination of his employment on December 31, 2009, and payment of the lump sum benefit of $2,194,293, offset by Retirement Plan benefits.

NONQUALIFIED DEFERRED COMPENSATION IN 2009

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	31,050	1,951,366	819,376	(68,253)	6,690,943
David R. McHale	--	52,846	35,015	--	298,328
Leon J. Olivier	137,500	60,398	192,229	(30,312)	1,660,946
Gregory B. Butler	--	53,807	53,469	(42,735)	505,556
James B. Robb	8,000	4,650	32,488	--	73,267

(1)

Reflects base salary deferrals by the Named Executive Officers under the 2009 Deferral Plan. Named Executive Officers who participate in the Deferral Plan are provided with a variety of investment opportunities, which the individual can modify and reallocate at any time. Fund gains and losses are updated daily by our recordkeeper, Fidelity Investments. Contributions by the Named Executive Officer are vested at all times; however, the employer matching contribution vests after three years and will be forfeited if the executive s employment terminates, other than for retirement, prior to vesting.

(2)

Includes employer matching contributions made to the Deferral Plan as of December 31, 2009 and posted on January 31, 2010, as reported in the All Other Compensation column of the Summary Compensation Table (Mr. Shivery: $23,700; Mr. Olivier: $9,150; and Mr. Robb: $4,650). 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 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 $22.40 per share, the closing price of the common shares on February 24, 2009, the last trading day preceding the vesting date of February 25, 2009. 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, 2009 plus the value of vested RSUs for which the distribution of common shares is currently deferred, based on $25.79 per share, the closing price of NU s common shares on December 31, 2009.

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 compensation or benefits for Messrs. Olivier and Robb under the terms of the Special Severance Program for Officers of Northeast Utilities System Companies (SSP)), 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 of NU effected through (i) the acquisition of 20% or more of the combined voting power of 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 Northeast Utilities, or a sale or disposition of all or substantially all of the assets of Northeast Utilities other than to an entity with respect to which following completion of the transaction more than 50% (75% for Messrs. Olivier and Robb) of common shares or other voting securities is then owned by all or substantially all of the persons who were the beneficial owners of common shares and other voting securities immediately prior to such transaction.

The discussion and tables below reflect the amount of compensation that would be payable to each of the Named Executive Officers 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, 2009, the last business day of the fiscal year as required under Securities and Exchange Commission reporting requirements.

Payments Upon Termination

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

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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;

.

Pay for unused vacation; and

.

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 ($)	Butler ($)	Robb ($)

Incentive Programs					
Annual Incentives	--	--	--	--	--
Performance Cash	--	--	--	--	--
Performance Shares	--	--	--	--	--
RSUs (1)	6,281,838	298,328	406,038	484,670	--
Pension and Deferred Compensation					
Retirement Plan (2)	245,892	296,990	360,719	162,160	--
Supplemental Plan	--	--	--	--	--
Special Retirement Benefit (3)	--	--	1,689,281	--	--
Deferral Plan (4)	409,106	--	1,254,908	20,886	24,226
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	6,936,836	595,318	3,710,946	667,716	24,226

(1)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2009, had been deferred upon vesting and remained deferred.

(2)

Represents the actuarial present values at the end of 2009 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 and Olivier: 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 appearing above.

(3)

Represents the actuarial present values at the end of 2009 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. 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. Pension amounts reflected in the table are present values at the end of 2009 of benefits payable to each NEO upon termination.

(4)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2009.

II.

Post-Employment Compensation: Voluntary Termination

Type of Payment	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Robb ($)**
Incentive Programs					
Annual Incentives (1)	1,645,650	555,728	558,415	414,009	316,500
Performance Cash (2)	3,187,500	367,875	684,011	316,870	--
Performance Shares (3)	295,720	--	78,573	--	--
RSUs (4)	7,831,844	298,328	717,303	484,670	--
Pension and Deferred Compensation					
Retirement Plan (5)	245,892	296,990	360,719	162,160	--
Supplemental Plan (6)	5,499,657	--	--	--	--
Special Retirement Benefit (7)	2,273,214	--	1,833,574	--	--
Deferral Plan (8)	409,106	--	1,254,908	20,886	24,226
Other Benefits					
Health and Welfare Benefits (9)	111,089	--	--	--	--
Perquisites	--	--	--	--	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement	--	--	--	--	--
Separation Payment for Liquidated Damages	--	--	--	--	--
Total	21,499,672	1,518,921	5,487,503	1,398,595	340,726

(1)

Represents the actual 2009 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" above.

(2)

Represents the actual performance cash award under the 2007 2009 Long-Term Incentive Program for each Named Executive Officer. Also includes, for Messrs. Shivery and Olivier, prorated performance cash awards under the 2008

2010 and 2009 2011 Long-Term Incentive 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" above.

(3)

Includes, for Messrs. Shivery and Olivier, the prorated performance share award under the 2009 2011 Long-Term Incentive Program, because each of them would be considered to be a "retiree" under those programs. Amounts are prorated for time worked in the three-year performance period, determined as described in the "Compensation Discussion and Analysis" above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2009, 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, 2010, would vest for Messrs. Shivery and Olivier based on time worked since February 25, 2009, 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 $25.79, the closing price of NU common shares on December 31, 2009.

(5)

Represents the actuarial present values at the end of 2009 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 and Olivier: 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 appearing above.

(6)

Represents the actuarial present value at the end of 2009 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 appearing above.

(7)

Represents the actuarial present values at the end of 2009 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 $2,194,293, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon voluntary termination. Pension amounts reflected in the table are present values at the end of 2009 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 appearing above.

(8)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2009.

(9)

Represents the costs estimated by our benefits consultants as of the end of 2009 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 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 ($)**	**Butler ($)**	**Robb ($)**
Incentive Programs					
Annual Incentives (1)	1,645,650	555,728	558,415	414,009	316,500
Performance Cash (2)	3,187,500	367,875	684,011	622,111	--
Performance Shares (3)	295,720	--	78,573	58,146	--
RSUs (4)	9,329,719	298,328	717,303	736,445	--
Pension and Deferred Compensation					
Retirement Plan (5)	245,892	296,990	360,719	397,831	--
Supplemental Plan (6)	5,499,657	--	--	--	--
Special Retirement Benefit (7)	3,788,690	3,587,502	1,833,574	2,266,014	--
Deferral Plan (8)	409,106	--	1,254,908	20,886	24,226
Other Benefits					
Health and Welfare Benefits (9)	123,912	41,890	--	17,078	--
Perquisites (10)	7,000	7,000	--	7,000	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement (11)	2,070,000	865,457	--	671,531	300,000
Separation Payment for Liquidated Damages (12)	2,070,000	865,457	--	671,531	300,000
Total	28,672,846	6,886,226	5,487,503	5,882,582	940,726

(1)

Represents the actual 2009 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" above.

(2)

Represents the actual performance cash award under the 2007 2009 Long-Term Incentive Program for each Named Executive Officer. Also includes, for Messrs. Shivery, Olivier and Butler, prorated performance cash awards under the 2008 2010 and 2009 2011 Long-Term Incentive 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" above.

(3)

Includes, for Messrs. Shivery, Olivier and Butler, a prorated performance share award under the 2009 2011 Long-Term Incentive Program. Amounts are prorated for time worked in the 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" above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2009, 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 and Mr. Robb, unvested RSUs that would have vested on February 25, 2010, vest based on time worked since February 25, 2009, 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 $25.79, the closing price of NU common shares on December 31, 2009.

(5)

Represents the actuarial present values at the end of 2009 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 and Olivier: 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 appearing above.

(6)

Represents the actuarial present value at the end of 2009 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 above.

(7)

Represents the actuarial present values at the end of 2009 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 other than for 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 other than for 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 $2,194,293, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon an involuntary termination other than for cause. Pension amounts reflected in the table are present values at the end of 2009 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 appearing above.

(8)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2009.

(9)

Represents the costs estimated by our benefits consultants as of the end of 2009 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.

(10)

Represents the cost of reimbursing fees for financial planning and tax preparation services to Messrs. Shivery, McHale, and Butler for two years.

(11)

Represents payments made as consideration for agreements by each of Messrs. Shivery, McHale, Butler, and Robb not to compete with NU or its subsidiaries following termination. Employment or other agreements with these Named Executive Officers provide for a lump-sum payment in an amount equal to the sum (one-half of the sum for Mr. Robb) of 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 Messrs. Shivery, McHale, Butler and Robb paid in addition to the non-compete agreement payments described in note (11). This payment is an amount equal to the sum (one-half of the sum for Mr. Robb) of their actual base salary paid in 2009 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 ($)**	**Butler ($)**	**Robb ($)**
Incentive Programs					
Annual Incentives (1)	1,645,650	555,728	558,415	414,009	316,500
Performance Cash (2)	3,187,500	749,125	684,011	622,111	200,000
Performance Shares (3)	292,792	74,259	77,795	57,570	37,720
RSUs (4)	7,831,844	638,398	717,303	736,445	95,415
Pension and Deferred Compensation					
Retirement Plan (5)	265,667	831,895	360,719	269,240	--
Supplemental Plan (6)	5,295,389	3,963,775	--	1,435,035	--
Special Retirement Benefit (7)	2,200,220	--	1,833,574	--	--
Deferral Plan (8)	409,106	--	1,254,908	20,886	73,267
Other Benefits					
Health and Welfare Benefits (9)	111,089	--	--	--	--
Perquisites	--	--	--	--	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement	--	--	--	--	--
Separation Payment for Liquidated Damages	--	--	--	--	--
Total	21,239,257	6,813,180	5,486,725	3,555,296	722,902

(1)

Represents the actual 2009 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above.

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(2)

Represents the actual performance cash award under the 2007 2009 Long-Term Incentive Program determined as described in the Compensation Discussion and Analysis above, plus performance cash awards at target under each of the 2008 2010 Long-Term Incentive Program and 2009 2011 Long-Term Incentive Program prorated for time worked in each three-year performance period.

(3)

Represents the performance share award at target under the 2009 2011 Long-Term Incentive Program prorated for time worked in the three-year performance period, as described in the Compensation Discussion and Analysis above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2009, 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, 2010, vest based on time worked since February 25, 2009. The values were calculated by multiplying the number of RSUs by $25.79, the closing price of NU common shares on December 31, 2009.

(5)

Under our Long-Term Disability (LTD) program, disabled participants in the Retirement Plan are allowed to continue to accrue service in the Retirement Plan during the period when they are receiving disability payments. Disability payments stop when the LTD participant elects to commence pension payments, but not later than age 65. We have assumed similar treatment in the development of the pension amounts reported in this table. For purposes of valuing the pension benefits, we have assumed that each Named Executive Officer would remain on LTD until 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 2009 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. Olivier: immediately; and Mr. Butler: age 62. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table appearing above.

(6)

Represents the actuarial present value at the end of 2009 of the benefit payable from the Supplemental Plan to each NEO other than Mr. Olivier under the assumptions discussed in note (5). 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 appearing above.

(7)

Represents the actuarial present values at the end of 2009 of the amounts payable to the Named Executive Officers under the assumptions discussed in note (5), 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 $2,194,293, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon disability termination. Mr. Shivery s benefit would be paid as an annuity calculated as described in Notes 1 and 2 to the Pension Benefits Table appearing above.

(8)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2009.

(9)

Represents the costs estimated by our benefits consultants as of the end of 2009 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 ($)**	**Butler ($)**	**Robb ($)**
Incentive Programs					
Annual Incentives (1)	1,645,650	555,728	558,415	414,009	316,500
Performance Cash (2)	3,187,500	749,125	684,011	622,111	200,000
Performance Shares (3)	292,792	74,259	77,795	57,570	37,720
RSUs (4)	7,831,844	638,398	717,303	736,445	95,415
Pension and Deferred Compensation					
Retirement Plan (5)	124,181	1,171,164	301,203	159,074	--
Supplemental Plan (5)	2,777,456	3,933,933	--	1,138,176	--
Special Retirement Benefit (6)	1,148,027	--	1,893,090	--	--
Deferral Plan (7)	409,106	--	1,254,908	20,886	73,267
Other Benefits					
Health and Welfare Benefits (8)	58,514	--	--	--	--
Perquisites	--	--	--	--	--
Separation Payments					
Excise Tax & Gross-Up	--	--	--	--	--
Separation Payment for Non-Compete Agreement	--	--	--	--	--
Separation Payment for Liquidated Damages	--	--	-	--	--
Total	17,475,070	7,122,607	5,486,725	3,148,271	722,902

(1)

Represents the actual 2009 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above.

(2)

Represents the actual performance cash award under the 2007 2009 Long-Term Incentive Program determined as described in the Compensation Discussion and Analysis above, plus performance cash awards at target under each of the 2008 2010 Long-Term Incentive Program and the 2009 2011 Long-Term Incentive Program prorated for time worked in each three-year performance period.

(3)

Represents the performance share award at target under the 2009 2011 Long-Term Incentive Program prorated for time worked in the three-year performance period, as described in the Compensation Discussion and Analysis above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2009, 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, 2010, vest based on time worked since February 25, 2009. The values were calculated by multiplying the number of RSUs by $25.79, the closing price of NU common shares on December 31, 2009.

(5)

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 appearing above.

(6)

Represents the actuarial present values at the end of 2009 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 $2,194,293, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier s spouse upon death. Pension amounts reflected in the table are present values at the end of 2009 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 appearing above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2009.

(8)

Represents the costs estimated by our benefits consultants as of the end of 2009 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 or other agreements with Messrs. Shivery, McHale, Olivier, Butler, and Robb include change of control benefits. Mr. Olivier participates in the SSP, which provides benefits upon termination of employment in connection with a change of control. The employment agreements and the SSP are binding on NU and, except for Mr. Shivery s agreement, on certain of NU s majority-owned subsidiaries, including CL&P. 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, and the agreement with Mr. Robb.

Pursuant to the employment or other 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 NU and its subsidiaries:

.

A lump sum severance payment of two-times (one-times for Mr. Olivier and one-half times for Mr. Robb) 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 (one-half times Base Compensation for Mr. Robb);

.

Active health benefits continuation, provided for three years (two years for Mr. Olivier, none for Mr. Robb);

.

Retirement health coverage (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 our 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. Robb, who does not participate in the Supplemental Plan);

.

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. Robb).

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 .

VI.

Post-Employment Compensation: Termination Following a Change of Control

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Butler ($)	Robb ($)
Incentive Programs					
Annual Incentives (1)	1,645,650	555,728	558,415	414,009	316,500
Performance Cash (2)	4,740,000	1,136,625	1,070,469	927,352	400,000
Performance Shares (3)	878,375	222,777	233,386	172,710	113,161
RSUs (4)	9,329,719	1,001,072	1,065,302	1,006,468	319,476
Pension and Deferred Compensation					
Retirement Plan (5)	245,892	296,990	360,719	162,160	--
Supplemental Plan (6)	5,499,657	--	--	--	--
Special Retirement Benefit (7)	4,546,428	3,731,373	1,833,574	2,784,513	--
Deferral Plan (8)	409,106	--	1,254,908	20,886	73,267
Other Benefits					
Health and Welfare Benefits (9)	139,895	259,572	6,773	30,191	--
Perquisites (10)	8,500	8,500	--	8,500	--
Separation Payments					
Excise Tax and Gross-Up (11)	3,506,888	3,244,828	--	2,217,997	--
Separation Payment for Non-Compete Agreement (12)	2,070,000	865,457	907,501	671,531	300,000
Separation Payment for Liquidated Damages (13)	4,140,001	1,730,914	907,501	1,343,062	300,000
Total	37,160,111	13,053,836	8,198,548	9,759,379	1,822,404

(1)

Represents the actual 2009 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above.

(2)

Represents the actual performance cash award under the 2007 2009 Long-Term Incentive Program for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above, plus performance cash awards at target for each Named Executive Officer under each of the 2008 2010 Long-Term Incentive Program and the 2009 2011 Long-Term Incentive Program.

(3)

Represents the performance share award at target for each Named Executive Officer under the 2009 2011 Long-Term Incentive Program, determined as described in the Compensation Discussion and Analysis above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2009, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. The values were calculated by multiplying the number of RSUs by $25.79, the closing price of NU common shares on December 31, 2009.

(5)

Represents the actuarial present values at the end of 2009 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: 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 appearing above.

(6)

Represents the actuarial present value at the end of 2009 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 appearing above.

(7)

Represents the actuarial present values at the end of 2009 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 $2,194,293, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon termination following a Change in Control. Pension amounts reflected in the table are present values at the end of 2009 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 appearing above.

(8)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2009.

(9)

Represents the costs estimated by our benefits consultants as of the end of 2009 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 participates in the SSP and is 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.

(10)

Represents the cost of reimbursing fees for financial planning and tax preparation services to Messrs. Shivery, McHale, and Butler for three years.

(11)

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. Robb 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 6.5%, and the Medicare tax rate of 1.45%.

(12)

Represents payments made as consideration for each Named Executive Officer s agreement not to compete with the company following termination of employment. This payment equals the sum (one-half of the sum for Mr. Robb) of the actual base salary paid in 2009 plus annual incentive award at target. Agreements with each Named Executive Officer provide for a lump-sum payment 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.

(13)

Represents severance payments to each Named Executive Officer paid in addition to the non-compete agreement payments described in note (12). For Messrs. Shivery, McHale, and Butler, this payment equals two-times the sum of the actual base salary paid in 2009 plus annual incentive award at target. For Mr. Olivier, this payment equals the sum of the actual base salary paid in 2009 plus annual incentive award at target. For Mr. Robb this payment equals one-half of the sum of his actual base salary paid in 2009 plus 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, 2010.

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 percent of the outstanding common stock of CL&P. The following table sets forth, as of February 15, 2010, 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, Director [5]	24,193	-	24,193	*	51,871
David R. McHale, CFO, Director [5][7]	23,962	-	23,962	*	46,465
Jeffrey D. Butler, President, Chief Operating Officer, Director [5]	693	-	693	*	5,740
Gregory B. Butler, Senior Vice President and General Counsel, Director [4][5][6]	37,351	-	37,351	*	45,314
James B. Robb, Director [5]	5,094	-	5,094	*	16,830
Charles W. Shivery, Chairman, Director [5][8]	51,358	29,024	80,382	*	399,462
All directors and Executive Officers as a Group (8 persons)	156,533	29,024	185,557	*	588,443

*Less than 1 percent 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 note below.

(2)

Reflects common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 15, 2010.

(3)

Includes unissued common shares consisting of restricted share units, deferred restricted share units and/or deferred shares, including dividend equivalents, as to which none of the individuals has voting or investment power. Also includes phantom common shares, representing employer matching contributions distributable only in cash, held by executive officers who participate in our Deferred Compensation Plan for Executives. Accordingly, these securities have been excluded from the "Total" column.

(4)

Includes 33,948 shares owned jointly by Mr. Gregory Butler and his spouse with whom he shares voting and investment power.

(5)

Includes common shares held in the 401K Plan in the employer stock ownership plan account over which the holder has sole voting and investment power (Mr. Jeffrey Butler: 46 shares; Mr. Gregory Butler: 2,977 shares; Mr. McHale: 3,655 shares; Mr. Olivier: 1,649 shares; Mr. Robb: 453 shares; and Mr. Shivery: 1,786 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. Jeffrey Butler: 647 shares; Mr. Gregory Butler: 426 shares; and Mr. McHale: 1,699 shares).

(7)

Includes 108 shares held by Mr. McHale in the 401k Plan TRAESOP/PAYSOP account over which Mr. McHale has sole voting and investment power.

(8)

Includes 1,500 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, as of December 31, 2009, in accordance with the rules of the SEC:

Plan Category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)**	**Weighted-average exercise price of outstanding options, warrants and rights (b)**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)**
Equity compensation plans approved by security holders	(a) 1,294,261	(b) $18.96	(c) 8,312,825
Equity compensation plans not approved by security holders (d)	--	--	--
Total	1,294,261 (a)	$18.96	8,312,825

(a)

Includes 225,216 common shares to be issued upon exercise of options, 970,006 common shares for distribution of restricted share units, and 99,039 performance shares issuable at target, all 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 6,048,343 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, 2010.

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 for Trustees, executive officers or Directors 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, 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.

NU s Related Party Transactions 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 percent 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, 2010.

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 $2,727,410 and $3,053,830 for the years ended December 31, 2009 and 2008, 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, 2009 and 2008 totaled $2,636,775 and $2,914,860, 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, 2009 and 2008, as well as auditing the implementation of new accounting standards and the accounting for new contracts and proposed transactions.

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, 2009 and 2008 totaled $66,000 and $117,500, respectively, primarily related to the examination of management s assertions about the securitization subsidiaries of CL&P, PSNH and WMECO.

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, 2009 and 2008 totaled $23,135 and $20,000, respectively. These services related primarily to the reviews of tax returns and reviewing the tax impacts of proposed transactions in 2009 and reviewing tax returns in 2008. There were no services related to tax advice or tax planning in 2008.

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, 2009 and 2008, consisting of a license fee for access to an accounting research tool.

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 2009, all services described above were pre-approved by the Audit Committee. During 2008, the only audit related services provided by Deloitte & Touche LLP 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 Deloitte & Touche LLP 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 Deloitte & Touche LLP received a fee of $5,000. The Audit Committee approved these de minimis services prior to the completion of the financial statement audit. Deloitte & Touche LLP did not provide any other services that were not pre-approved by the Audit Committee.

The Audit Committee has considered whether the provision by Deloitte & Touche LLP 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 Deloitte & Touche LLP was and is independent of NU and its subsidiaries in all respects.

PART IV

Item 15.

Exhibits and Financial Statement Schedules

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, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2010

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 26, 2010
/s/ David R. McHale David R. McHale	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2010
/s/	Vice President - Accounting and Controller	February 26, 2010

Jay S. Buth
Jay S. Buth

/s/	Trustee	February 26, 2010

Richard H. Booth
Richard H. Booth

/s/	Trustee	February 26, 2010

John S. Clarkeson
John S. Clarkeson

/s/	Trustee	February 26, 2010

Cotton M. Cleveland
Cotton M. Cleveland

/s/	Trustee	February 26, 2010

Sanford Cloud, Jr.
Sanford Cloud, Jr.

/s/	Trustee	February 26, 2010

James F. Cordes
James F. Cordes

/s/	Trustee	February 26, 2010

E. Gail de Planque
E. Gail de Planque

/s/	Trustee	February 26, 2010

John G. Graham
John G. Graham

/s/	Trustee	February 26, 2010

Elizabeth T. Kennan
Elizabeth T. Kennan

/s/	Trustee	February 26, 2010
Kenneth R. Leibler Kenneth R. Leibler		
/s/	Trustee	February 26, 2010
Robert E. Patricelli Robert E. Patricelli		
/s/	Trustee	February 26, 2010
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 (Principal Executive Officer)	February 26, 2010

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

Signature	Title	Date
/s/ Charles W. Shivery Charles W. Shivery	Chairman and a Director	February 26, 2010
/s/ Leon J. Olivier Leon J. Olivier	Chief Executive Officer and a Director (Principal Executive Officer)	February 26, 2010
/s/	President and Chief Operating Officer	February 26, 2010

Jeffrey D. Butler Jeffrey D. Butler	and a Director	
/s/	Executive Vice President and Chief Financial	February 26, 2010
David R. McHale David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Director	February 26, 2010
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 26, 2010
Jean M. LaVecchia Jean M. LaVecchia		
/s/	Director	February 26, 2010
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 26, 2010
Jay S. Buth Jay S. Buth		

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 (Principal Executive Officer)	February 26, 2010

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 26, 2010
Charles W. Shivery Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 26, 2010
Leon J. Olivier Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 26, 2010

Gary A. Long Gary A. Long	and a Director	
/s/	Executive Vice President and Chief Financial	February 26, 2010
David R. McHale David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Director	February 26, 2010
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 26, 2010
Jean M. LaVecchia Jean M. LaVecchia		
/s/	Director	February 26, 2010
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 26, 2010
Jay S. Buth Jay S. Buth		

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 (Principal Executive Officer)	February 26, 2010

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 26, 2010
Charles W. Shivery Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 26, 2010
Leon J. Olivier Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 26, 2010

Peter J. Clarke Peter J. Clarke	and a Director	
/s/	Executive Vice President and Chief Financial	February 26, 2010
David R. McHale David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Director	February 26, 2010
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 26, 2010
Jean M. LaVecchia Jean M. LaVecchia		
/s/	Director	February 26, 2010
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 26, 2010
Jay S. Buth Jay S. Buth		

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, 2009.

February 26, 2010

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, 2009 and 2008, 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, 2009. 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, 2009, 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 and financial statement schedules, 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP

Hartford, Connecticut

February 26, 2010

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2009	2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 26,952	$ 89,816
Receivables, net	512,770	698,755
Unbilled revenues	229,326	218,440
Fuel, materials and supplies - current	277,085	300,049
Marketable securities - current	66,236	78,452
Derivative assets - current	31,785	31,373
Prepayments and other	123,700	88,679
Total Current Assets	1,267,854	1,505,564
Property, Plant and Equipment, Net	8,839,965	8,207,876
Deferred Debits and Other Assets:		
Regulatory assets	3,244,931	3,502,606
Goodwill	287,591	287,591
Marketable securities - long-term	54,905	30,757
Derivative assets - long-term	189,751	241,814
Other	172,682	212,272
Total Deferred Debits and Other Assets	3,949,860	4,275,040
Total Assets	$ 14,057,679	$ 13,988,480

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2009	2008
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 100,313	$ 618,897
Long-term debt - current portion	66,286	54,286
Accounts payable	457,582	678,614
Accrued taxes	50,246	12,527
Accrued interest	83,763	69,818
Derivative liabilities - current	37,617	100,919
Other	183,605	168,401
Total Current Liabilities	979,412	1,703,462
Rate Reduction Bonds	442,436	686,511
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,380,143	1,223,461
Accumulated deferred investment tax credits	22,145	25,371
Regulatory liabilities	485,706	592,540
Derivative liabilities - long-term	955,646	912,426
Accrued pension	781,431	740,930
Other	823,723	864,105
Total Deferred Credits and Other Liabilities	4,448,794	4,358,833
Capitalization:		
Long-Term Debt	4,492,935	4,103,162
Noncontrolling Interest in Consolidated Subsidiary:		
Preferred stock not subject to mandatory redemption	116,200	116,200
Common Shareholders' Equity:		
Common shares	977,276	881,061
Capital surplus, paid in	1,762,097	1,475,006
Deferred contribution plan - employee stock ownership plan	(2,944)	(15,481)
Retained earnings	1,246,543	1,078,594
Accumulated other comprehensive loss	(43,467)	(37,265)
Treasury stock	(361,603)	(361,603)
Common Shareholders' Equity	3,577,902	3,020,312
Total Capitalization	8,187,037	7,239,674

Commitments and Contingencies (Note 7)		
Total Liabilities and Capitalization	$ 14,057,679	$ 13,988,480

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, 2009	2008	2007
Operating Revenues	$ 5,439,430	$ 5,800,095	$ 5,822,226
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	2,629,619	2,996,180	3,350,673
Other	1,001,190	1,021,704	961,285
Maintenance	234,173	254,038	211,589
Depreciation	309,618	278,588	265,297
Amortization of regulatory assets, net	13,315	186,396	40,674
Amortization of rate reduction bonds	217,941	204,859	201,039
Taxes other than income taxes	282,199	267,565	252,188
Total operating expenses	4,688,055	5,209,330	5,282,745
Operating Income	751,375	590,765	539,481
Interest Expense:			
Interest on long-term debt	224,712	193,883	162,841
Interest on rate reduction bonds	36,524	50,231	61,580
Other interest	12,401	25,031	15,824
Interest expense, net	273,637	269,145	240,245
Other Income, Net	37,801	50,428	61,639
Income from Continuing Operations Before Income Tax Expense	515,539	372,048	360,875
Income Tax Expense	179,947	105,661	109,420
Income from Continuing Operations	335,592	266,387	251,455
Discontinued Operations (Note 1B):			
Income from discontinued operations	-	-	435
Gains from sale/disposition of discontinued operations	-	-	2,054
Income tax expense	-	-	1,902
Income from Discontinued Operations	-	-	587
Net Income	335,592	266,387	252,042
Net Income Attributable to Noncontrolling Interest:			
Preferred dividends of subsidiary	5,559	5,559	5,559
	$ 330,033	$ 260,828	$ 246,483

Net Income Attributable to Controlling Interest						
Basic Earnings Per Common Share:						
Income from Continuing Operations Attributable to Controlling Interest	$	1.91	$	1.68	$	1.59
Income from Discontinued Operations Attributable to Controlling Interest		-		-		-
Basic Earnings Per Common Share	$	1.91	$	1.68	$	1.59
Fully Diluted Earnings Per Common Share:						
Income from Continuing Operations Attributable to Controlling Interest	$	1.91	$	1.67	$	1.59
Income from Discontinued Operations Attributable to Controlling Interest		-		-		-
Fully Diluted Earnings Per Common Share	$	1.91	$	1.67	$	1.59
Weighted Average Common Shares Outstanding:						
Basic		172,567,928		155,531,846		154,759,727
Fully Diluted		172,717,246		155,999,240		155,304,361
Amounts Attributable to Controlling Interest:						
Income from Continuing Operations	$	330,033	$	260,828	$	245,896
Income from Discontinued Operations		-		-		587
Net Income Attributable to Controlling Interest	$	330,033	$	260,828	$	246,483

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, 2009	2008	2007
Net Income	$ 335,592	$ 266,387	$ 252,042
Other comprehensive (loss)/income, net of tax:			
Qualified cash flow hedging instruments	200	(6,909)	(3,591)
Changes in unrealized gains/losses on other securities	(976)	(1,669)	(101)
Change in funded status of pension, SERP and other postretirement benefit plans	(5,426)	(38,046)	8,553
Other comprehensive (loss)/income, net of tax	(6,202)	(46,624)	4,861
Comprehensive income attributable to noncontrolling interest	(5,559)	(5,559)	(5,559)
Comprehensive Income Attributable to Controlling Interest	$ 323,831	$ 214,204	$ 251,344

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Thousands of Dollars, except share information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Deferred Contribution Plan - ESOP	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Common Shareholders' Equity
Balance as of January 1, 2007	154,23[illegible]	$ [illegible]101	$ 1,449,586	$ (34,766)	$ 862,660	$ 4,498	$ (360,900)	$ 2,798,179
Adoption of accounting guidance for uncertain tax positions					(41,816)			(41,816)
Net income					252,042			252,042
Dividends on common shares - $0.775 per share					(120,535)			(120,535)
Issuance of common shares, $5 par value	504,4[illegible]	2,522	6,534					9,056
Dividends on preferred shares of CL&P					(5,559)			(5,559)
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
			140					140

Capital stock expenses, net								
Other comprehensive income						4,861		4,861
Balance as of December 31, 2007	155,079,770	979,623	1,465,946	(26,352)	946,792	9,359	(361,533)	2,913,835
Net income					266,387			266,387
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
Dividends on preferred shares of CL&P					(5,559)			(5,559)
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	981,061	1,475,006	(15,481)	1,078,594	(37,265)	(361,603)	3,020,312
Adoption of accounting guidance for other-than-temporary impairments (Note 1D)					728	(728)		-
Net income					335,592			335,592
Dividends on common shares - $0.95 per share					(162,812)			(162,812)
	19,242,963	96,215	293,502					389,717

Issuance of common shares, $5 par value								
Dividends on preferred shares of CL&P					(5,559)			(5,559)
Allocation of benefits - ESOP	542,724		(98)	12,537				12,439
Change in restricted shares, net			5,303					5,303
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			913					913
Capital stock expenses, net			(12,529)					(12,529)
Other comprehensive loss						(5,474)		(5,474)
Balance as of December 31, 2009	175,620,072	$ 977,276	$ 1,762,097	$ (2,944)	$ 1,246,543	$ (43,467)	$ (361,603)	$ 3,577,902

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)	2009	2008	2007
Operating Activities:			
Net income	$ 335,592	$ 266,387	$ 252,042
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Bad debt expense	53,947	28,573	29,140
Depreciation	309,618	278,588	265,297
Deferred income taxes	125,890	86,810	6,933
Pension and PBOP expense/(income), net of capitalized portion and PBOP contributions	21,572	(3,839)	10,865
Allowance for equity funds used during construction	(9,397)	(29,028)	(17,417)
Regulatory overrecoveries/(refunds and underrecoveries), net	37,868	(185,252)	48,725
Amortization of regulatory assets, net	13,315	186,396	40,674
Amortization of rate reduction bonds	217,941	204,859	201,039
Deferred contractual obligations	(29,155)	(32,326)	(41,950)
Derivative assets and liabilities	(18,798)	(37,052)	(43,808)
Other	12,549	9,567	(7,517)
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	91,081	(141,879)	(65,381)
Investments in securitizable assets	-	(25,787)	33,531
Fuel, materials and supplies	25,957	(74,531)	(33,727)
Taxes receivable/accrued	16,194	63,251	(392,611)
Accounts payable	(208,180)	72,791	(49,554)
Other current assets and liabilities	(6,876)	(12,551)	17,713
Net cash flows provided by operating activities	989,118	654,977	253,994
Investing Activities:			
Investments in property and plant	(908,146)	(1,255,407)	(1,114,824)
Proceeds from sales of marketable securities	208,947	259,361	254,832
Purchases of marketable securities	(211,243)	(262,357)	(261,777)
Rate reduction bond escrow and other deposits	594	1,686	63,722

Other investing activities	7,369	3,360	(9,419)
Net cash flows used in investing activities	(902,479)	(1,253,357)	(1,067,466)
Financing Activities:			
Issuance of common shares	389,717	5,524	9,056
Cash dividends on common shares	(162,381)	(129,077)	(120,988)
Cash dividends on preferred stock of subsidiary	(5,559)	(5,559)	(5,559)
(Decrease)/increase in short-term debt	(518,584)	539,897	79,000
Issuance of long-term debt	462,000	760,000	655,000
Retirements of long-term debt	(54,286)	(261,286)	(4,877)
Retirements of rate reduction bonds	(244,075)	(230,925)	(259,722)
Financing fees	(17,262)	(7,003)	(8,620)
Other financing activities	927	1,521	3,375
Net cash flows (used in)/provided by financing activities	(149,503)	673,092	346,665
Net (decrease)/increase in cash and cash equivalents	(62,864)	74,712	(466,807)
Cash and cash equivalents - beginning of year	89,816	15,104	481,911
Cash and cash equivalents - end of year	$ 26,952	$ 89,816	$ 15,104

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION

		As of December 31,	
(Thousands of Dollars)		2009	2008
Common Shareholders Equity		$3,577,902	$3,020,312
Preferred Stock:			
CL&P Preferred Stock Not Subject to Mandatory Redemption -			
$50 par value - authorized 9,000,000 shares in 2009 and 2008;			
2,324,000 shares outstanding in 2009 and 2008;			
Dividend rates of $1.90 to $3.24;			
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	7.19% in 2009; 6.20% to 7.19% in 2008	12,857	67,143
2014-2018	4.80% to 6.90%	1,205,000	1,205,000
2019-2024	4.50% to 8.48%	609,845	209,845
2034-2037	5.35% to 6.375%	830,000	830,000
Total First Mortgage Bonds		2,657,702	2,311,988
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 (Note 11)	5.25% in 2009 and 3.35% and Variable Rate in 2008	62,000	62,000
Other:			
2012-2015	5.00% to 7.25%	618,000	618,000
2034-2037	5.90% to 6.70%	90,000	90,000
Total Pollution Control Notes and Other		1,592,985	1,592,985
Total First Mortgage Bonds, Pollution Control Notes and Other		4,250,687	3,904,973
Fees and interest due for spent nuclear fuel disposal costs		300,647	298,555
Change in fair value resulting from interest rate hedge instrument		13,258	20,828
Unamortized premium and discount, net		(5,371)	(4,908)
Reacquisition of Pollution Control Notes		-	(62,000)
Total Long-Term Debt		4,559,221	4,157,448
Less: Amounts due within one year		66,286	54,286
Long-Term Debt		4,492,935	4,103,162

Total Capitalization	$8,187,037	$7,239,674

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 The Connecticut Light and Power Company and subsidiaries (CL&P or the Company) and of other sections of this annual report. CL&P 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, 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, 2009.

February 26, 2010

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, 2009 and 2008, and the related consolidated statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009, 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 and financial statement schedules, 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 The Connecticut Light and Power Company and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP

Hartford, Connecticut

February 26, 2010

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2009	2008
ASSETS		
Current Assets:		
Cash	$ 45	$ -
Receivables, net	327,969	416,304
Accounts receivable from affiliated companies	2,362	11,215
Notes receivable from affiliated companies	97,775	-
Unbilled revenues	140,632	127,844
Materials and supplies	65,623	70,676
Derivative assets - current	24,593	30,478
Prepayments and other	18,385	15,685
Total Current Assets	677,384	672,202
Property, Plant and Equipment, Net	5,340,561	5,089,124
Deferred Debits and Other Assets:		
Regulatory assets	2,068,778	2,274,088
Derivative assets - long-term	183,231	215,288
Other	94,610	85,416
Total Deferred Debits and Other Assets	2,346,619	2,574,792
Total Assets	$ 8,364,564	$ 8,336,118

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2009	2008
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to banks	$ -	$ 187,973
Notes payable to affiliated companies	-	102,725
Long-term debt - current portion	62,000	-
Accounts payable	242,853	353,584
Accounts payable to affiliated companies	48,795	57,053
Accrued taxes	36,860	24,839
Accrued interest	49,867	37,567
Derivative liabilities - current	9,770	8,873
Other	100,846	92,444
Total Current Liabilities	550,991	865,058
Rate Reduction Bonds	195,587	378,195
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	901,527	811,405
Accumulated deferred investment tax credits	16,355	18,805
Deferred contractual obligations	114,495	132,687
Regulatory liabilities	316,160	363,547
Derivative liabilities - long-term	913,349	848,106
Accrued pension	51,319	89,254
Accrued postretirement benefits	94,947	98,587
Other	200,090	215,620
Total Deferred Credits and Other Liabilities	2,608,242	2,578,011
Capitalization:		
Long-Term Debt	2,520,361	2,270,414
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Common Stockholder's Equity:		
Common stock	60,352	60,352
Capital surplus, paid in	1,601,792	1,454,198
Retained earnings	714,210	617,276
Accumulated other comprehensive loss	(3,171)	(3,586)
Common Stockholder's Equity	2,373,183	2,128,240

Total Capitalization		5,009,744		4,514,854
Commitments and Contingencies (Note 7)				
Total Liabilities and Capitalization	$	8,364,564	$	8,336,118

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)	2009	2008	2007
Operating Revenues	$ 3,424,538	$ 3,558,361	$ 3,681,817
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	1,690,671	1,845,367	2,277,054
Other	571,024	557,565	535,750
Maintenance	117,822	130,365	108,001
Depreciation	186,922	162,636	152,005
Amortization of regulatory assets, net	45,821	164,246	20,593
Amortization of rate reduction bonds	155,938	145,590	135,929
Taxes other than income taxes	191,234	179,201	167,943
Total operating expenses	2,959,432	3,184,970	3,397,275
Operating Income	465,106	373,391	284,542
Interest Expense:			
Interest on long-term debt	133,422	104,954	84,292
Interest on rate reduction bonds	19,061	29,129	37,728
Other interest	3,334	12,163	16,413
Interest expense, net	155,817	146,246	138,433
Other Income, Net	25,874	41,865	39,808
Income Before Income Tax Expense	335,163	269,010	185,917
Income Tax Expense	118,847	77,852	52,353
Net Income	$ 216,316	$ 191,158	$ 133,564

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 216,316	$ 191,158	$ 133,564
Other comprehensive income/(loss), net of tax:			
Qualified cash flow hedging instruments	445	(3,348)	(4,814)
Changes in unrealized gains/losses on other securities	(30)	(59)	(5)
Other comprehensive income/(loss), net of tax	415	(3,407)	(4,819)

Comprehensive Income	$	216,731	$	187,751	$	128,745

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, except share information)	Common Stock Shares	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total
Balance as of January 1, 2007	6,035,205	$ 60,352	$ 672,693	$ 513,344	$ 4,640	$1,251,029
Adoption of accounting guidance for uncertain tax positions				(24,030)		(24,030)
Net income				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 as of December 31, 2007	6,035,205	60,352	1,243,940	538,138	(179)	1,842,251
Net income				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 as of December 31, 2008	6,035,205	60,352	1,454,198	617,276	(3,586)	2,128,240
Adoption of accounting guidance for other-than-temporary impairments (Note 1D)				25	(25)	-
Net income				216,316		216,316
Dividends on preferred stock				(5,559)		(5,559)
Dividends on common stock				(113,848)		(113,848)
Allocation of benefits - ESOP			(48)			(48)
Capital stock expenses, net			51			51
Capital contributions from NU parent			147,591			147,591
Other comprehensive income					440	440
Balance as of December 31, 2009	6,035,205	$ 60,352	$1,601,792	$ 714,210	$ (3,171)	$2,373,183

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)	2009	2008	2007
Operating Activities:			
Net income	$ 216,316	$ 191,158	$ 133,564
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Bad debt expense	15,276	5,951	18,121
Depreciation	186,922	162,636	152,005
Deferred income taxes	52,900	47,653	28,725
Allowance for equity funds used during construction	(5,711)	(23,212)	(14,230)
Pension income and PBOP expense, net of capitalized portion and PBOP contributions	(10,709)	(19,257)	(10,334)
Regulatory overrecoveries/(refunds and underrecoveries), net	51,292	(153,843)	4,441
Amortization of regulatory assets, net	45,821	164,246	20,593
Amortization of rate reduction bonds	155,938	145,590	135,929
Deferred contractual obligations	(19,560)	(21,526)	(28,019)
Other	(13,460)	(5,932)	(11,544)
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	50,327	(125,241)	(44,025)
Investments in securitizable assets	-	(25,787)	33,531
Materials and supplies	(6,339)	(15,204)	(16,030)
Taxes receivable/accrued	25,823	60,864	(216,714)
Accounts payable	(85,773)	28,772	3,457
Other current assets and liabilities	5,718	20,885	10,263
Net cash flows provided by operating activities	664,781	437,753	199,733
Investing Activities:			
Investments in property and plant	(435,723)	(849,549)	(826,248)
Increase in NU Money Pool lending	(97,775)	-	-
Rate reduction bond escrow and other deposits	1,368	(2,991)	56,872
Other investing activities	3,520	548	3,784
	(528,610)	(851,992)	(765,592)

Net cash flows used in investing activities			
Financing Activities:			
Cash dividends on common stock	(113,848)	(106,461)	(79,181)
Cash dividends on preferred stock	(5,559)	(5,559)	(5,559)
(Decrease)/increase in short-term debt	(187,973)	187,973	-
(Decrease)/increase in NU Money Pool borrowings	(102,725)	63,900	(220,100)
Capital contributions from NU parent	147,591	210,000	570,661
Issuance of long-term debt	312,000	300,000	500,000
Reacquisition of long-term debt	-	(62,000)	-
Retirements of rate reduction bonds	(182,608)	(170,491)	(195,213)
Other financing activities	(3,004)	(3,661)	(7,521)
Net cash flows (used in)/provided by financing activities	(136,126)	413,701	563,087
Net increase/(decrease) in cash	45	(538)	(2,772)
Cash - beginning of year	-	538	3,310
Cash - end of year	$ 45	$ -	$ 538

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. PSNH 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, 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, 2009.

February 26, 2010

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, 2009 and 2008, and the related consolidated statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009, 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 and financial statement schedules, 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 Public Service Company of New Hampshire and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP

Hartford, Connecticut

February 26, 2010

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2009	2008
ASSETS		
Current Assets:		
Cash	$ 1,974	$ 195
Receivables, net	89,337	108,857
Notes receivable from affiliated companies	-	53,800
Accounts receivable from affiliated companies	286	264
Unbilled revenues	49,358	41,449
Taxes receivable	22,600	8,809
Fuel, materials and supplies - current	127,447	113,121
Accumulated deferred income taxes - current	8,075	27,345
Prepayments and other	28,312	16,223
Total Current Assets	327,389	370,063
Property, Plant and Equipment, Net	1,814,714	1,580,985
Deferred Debits and Other Assets:		
Regulatory assets	494,077	549,934
Other	61,011	127,851
Total Deferred Debits and Other Assets	555,088	677,785
Total Assets	$ 2,697,191	$ 2,628,833

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2009	2008
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ -	$ 45,227
Notes payable to affiliated companies	26,700	-
Accounts payable	109,521	160,692
Accounts payable to affiliated companies	20,083	31,140
Accrued interest	10,255	11,778
Derivative liabilities - current	18,785	77,369
Other	27,983	23,422
Total Current Liabilities	213,327	349,628
Rate Reduction Bonds	188,113	235,139
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	275,669	253,670
Accumulated deferred investment tax credits	211	355
Deferred contractual obligations	20,149	23,820
Regulatory liabilities	69,872	111,403
Derivative liabilities - long-term	7,635	14,846
Accrued pension	272,905	236,332
Accrued postretirement benefits	39,717	41,849
Other	45,893	41,297
Total Deferred Credits and Other Liabilities	732,051	723,572
Capitalization:		
Long-Term Debt	836,255	686,779
Common Stockholder's Equity:		
Common stock	-	-
Capital surplus, paid in	420,169	351,245
Retained earnings	307,988	283,219
Accumulated other comprehensive loss	(712)	(749)
Common Stockholder's Equity	727,445	633,715
Total Capitalization	1,563,700	1,320,494

Commitments and Contingencies (Note 7)

Total Liabilities and Capitalization	$	2,697,191	$	2,628,833

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2009	2008	2007
Operating Revenues	$ 1,109,591	$ 1,141,202	$ 1,083,072
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	520,529	558,313	530,680
Other	239,650	215,497	208,691
Maintenance	87,026	90,933	74,070
Depreciation	61,961	56,321	53,315
Amortization of regulatory (liabilities)/assets, net	(29,619)	9,254	7,470
Amortization of rate reduction bonds	47,482	45,644	52,344
Taxes other than income taxes	47,975	42,291	39,671
Total operating expenses	975,004	1,018,253	966,241
Operating Income	134,587	122,949	116,831
Interest Expense:			
Interest on long-term debt	33,045	32,655	26,029
Interest on rate reduction bonds	13,128	15,969	18,013
Other interest	316	1,539	2,243
Interest expense, net	46,489	50,163	46,285
Other Income, Net	9,462	7,277	6,682
Income Before Income Tax Expense	97,560	80,063	77,228
Income Tax Expense	31,990	21,996	22,794
Net Income	$ 65,570	$ 58,067	$ 54,434
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME			
Net Income	$ 65,570	$ 58,067	$ 54,434
Other comprehensive income/(loss), net of tax:			
Qualified cash flow hedging instruments	87	(1,418)	605
Changes in unrealized gains/losses on other securities	(50)	(101)	(11)
Other comprehensive income/(loss), net of tax	37	(1,519)	594
Comprehensive Income	$ 65,607	$ 56,548	$ 55,028

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 Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total
Balance as of January 1, 2007	301	$ -	$ 231,171	$236,215	$ 176	$ 467,562
Adoption of accounting guidance for uncertain tax positions				1,599		1,599
Net income				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 as of December 31, 2007	301	-	275,569	261,528	770	537,867
Net income				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 as of December 31, 2008	301	-	351,245	283,219	(749)	633,715
Adoption of accounting guidance for other-than-temporary impairments (Note 1D)				43	(43)	-
Net income				65,570		65,570

Dividends on common stock				(40,844)		(40,844)
Allocation of benefits - ESOP			(22)			(22)
Capital contributions from NU parent			68,946			68,946
Other comprehensive income					80	80
Balance as of December 31, 2009	301	$ -	$ 420,169	$307,988	$ (712)	$ 727,445

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF
CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2009	2008	2007
Operating activities:			
Net income	$ 65,570	$ 58,067	$ 54,434
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Bad debt expense	10,084	5,661	3,433
Depreciation	61,961	56,321	53,315
Deferred income taxes	35,270	25,001	(4,726)
Pension and PBOP expense, net of capitalized portion and PBOP contributions	15,519	12,350	7,258
Regulatory underrecoveries, net	(4,392)	(23,848)	(6,167)
Amortization of regulatory (liabilities)/assets, net	(29,619)	9,254	7,470
Amortization of rate reduction bonds	47,482	45,644	52,344
Deferred contractual obligations	(4,275)	(4,978)	(6,365)
Proceeds from insurance settlement	10,066	-	-
Other	(3,251)	(28,919)	(11,854)
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	1,505	(12,058)	(15,799)
Taxes receivable/accrued	(13,791)	(2,117)	4,144
Fuel, materials and supplies	59	(26,209)	15,882
Accounts payable	(77,738)	41,959	(8,178)
Other current assets and liabilities	(9,192)	7,148	2,102
Net cash flows provided by operating activities	105,258	163,276	147,293
Investing Activities:			
Investments in property and plant	(266,440)	(238,912)	(167,712)
Decrease/(increase) in NU Money Pool lending	53,800	(53,800)	-
Other investing activities	(1,278)	4,607	5,683
Net cash flows used in investing activities	(213,918)	(288,105)	(162,029)
Financing Activities:			
Cash dividends on common stock	(40,844)	(36,376)	(30,720)
(Decrease)/increase in short-term debt	(45,227)	35,227	10,000
Issuance of long-term debt	150,000	110,000	70,000

Increase/(decrease) in NU Money Pool borrowings	26,700	(11,300)	(25,200)
Capital contributions from NU parent	68,946	75,583	44,194
Retirements of rate reduction bonds	(47,026)	(46,879)	(51,813)
Other financing activities	(2,110)	(1,681)	(1,306)
Net cash flows provided by financing activities	110,439	124,574	15,155
Net increase/(decrease) in cash	1,779	(255)	419
Cash - beginning of year	195	450	31
Cash - end of year	$ 1,974	$ 195	$ 450

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. WMECO 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, 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 December 31, 2009.

February 26, 2010

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, 2009 and 2008, and the related consolidated statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009, 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 and financial statement schedules, 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 Western Massachusetts Electric Company and subsidiary as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP

Hartford, Connecticut

February 26, 2010

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2009	2008
ASSETS		
Current Assets:		
Cash	$ 1	$ -
Receivables, net	38,415	56,802
Accounts receivable from affiliated companies	191	575
Unbilled revenues	16,090	16,694
Taxes receivable	4,192	5,499
Materials and supplies current	8,314	3,825
Marketable securities current	28,261	46,428
Prepayments and other	1,774	2,380
Total Current Assets	97,238	132,203
Property, Plant and Equipment, Net	705,760	624,205
Deferred Debits and Other Assets:		
Regulatory assets	240,804	268,417
Marketable securities - long-term	28,500	9,322
Other	29,498	14,342
Total Deferred Debits and Other Assets	298,802	292,081
Total Assets	$ 1,101,800	$ 1,048,489

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

WESTERN MASSACHUSETTS ELECTRIC
COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2009	2008
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ -	$ 29,850
Notes payable to affiliated companies	136,100	31,600
Accounts payable	36,680	50,161
Accounts payable to affiliated companies	7,924	15,047
Accrued interest	5,274	5,824
Other	8,873	10,715
Total Current Liabilities	194,851	143,197
Rate Reduction Bonds	58,735	73,176
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	211,391	187,283
Accumulated deferred investment tax credits	1,499	1,753
Deferred contractual obligations	31,528	36,509
Regulatory liabilities	21,683	29,826
Accrued postretirement benefits	17,398	18,078
Other	12,433	16,649
Total Deferred Credits and Other Liabilities	295,932	290,098
Capitalization:		
Long-Term Debt	305,475	303,868
Common Stockholder's Equity:		
Common stock	10,866	10,866
Capital surplus, paid in	145,400	144,545
Retained earnings	90,549	82,549
Accumulated other comprehensive (loss)/income	(8)	190
Common Stockholder's Equity	246,807	238,150
Total Capitalization	552,282	542,018
Commitment and Contingencies (Note 7)		
Total Liabilities and Capitalization	$ 1,101,800	$ 1,048,489

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)	2009	2008	2007
Operating Revenues	$ 402,413	$ 441,527	$ 464,745
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	192,177	237,369	236,582
Other	85,591	76,929	98,837
Maintenance	17,895	20,720	18,618
Depreciation	22,454	21,025	20,868
Amortization of regulatory (liabilities)/assets, net	(2,980)	12,445	10,601
Amortization of rate reduction bonds	14,521	13,625	12,766
Taxes other than income taxes	14,174	12,867	12,322
Total operating expenses	343,832	394,980	410,594
Operating Income	58,581	46,547	54,151
Interest Expense:			
Interest on long-term debt	14,074	13,244	11,577
Interest on rate reduction bonds	4,335	5,133	5,839
Other interest	877	1,256	2,430
Interest expense, net	19,286	19,633	19,846
Other Income, Net	1,824	1,961	3,885
Income Before Income Tax Expense	41,119	28,875	38,190
Income Tax Expense	14,923	10,545	14,586
Net Income	$ 26,196	$ 18,330	$ 23,604

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 26,196	$ 18,330	$ 23,604
Other comprehensive loss, net of tax:			

Qualified cash flow hedging instruments	(79)	(79)	(704)
Changes in unrealized gains/losses on other securities	(119)	38	42
Other comprehensive loss, net of tax	(198)	(41)	(662)
Comprehensive Income	$ 25,998	$ 18,289	$ 22,942

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock		Capital Surplus,	Retained	Accumulated Other Comprehensive	
(Thousands of Dollars, except share information)	Shares	Amount	Paid In	Earnings	Income/(Loss)	Total
Balance as of January 1, 2007	434,653	$ 10,866	$ 114,544	$ 92,663	$ 893	$ 218,966
Adoption of accounting guidance for uncertain tax positions				437		437
Net income				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 as of December 31, 2007	434,653	10,866	128,228	103,925	231	243,250
Net income				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 as of December 31, 2008	434,653	10,866	144,545	82,549	190	238,150
Adoption of accounting guidance for other-than-temporary impairments (Note 1D)				7	(7)	-

Net income				26,196		26,196
Dividends on common stock				(18,203)		(18,203)
Allocation of benefits - ESOP			(8)			(8)
Capital contributions from NU parent			863			863
Other comprehensive loss					(191)	(191)
Balance as of December 31, 2009	434,653	$ 10,866	$ 145,400	$ 90,549	$ (8)	$ 246,807

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF
CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2009	2008	2007
Operating Activities:			
Net income	$ 26,196	$ 18,330	$ 23,604
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Bad debt expense	7,590	8,185	6,922
Depreciation	22,454	21,025	20,868
Deferred income taxes	22,908	12,222	(15,332)
Pension income and PBOP expense, net of capitalized portion, and PBOP contributions	(2,630)	(4,844)	(3,050)
Regulatory overrecoveries/(underrecoveries), net	589	(17,093)	32,129
Amortization of regulatory (liabilities)/assets, net	(2,980)	12,445	10,601
Amortization of rate reduction bonds	14,521	13,625	12,766
Deferred contractual obligations	(5,320)	(5,822)	(7,568)
Other	(227)	(3,875)	195
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	3,757	(14,210)	(9,749)
Materials and supplies	(4,489)	(1,490)	(478)
Accounts payable	(19,397)	22,186	1,417
Taxes receivable/accrued	1,307	4,081	(35,014)
Other current assets and liabilities	(2,150)	2,718	237
Net cash flows provided by operating activities	62,129	67,483	37,548
Investing Activities:			
Investments in property and plant	(105,440)	(78,253)	(47,315)
Proceeds from sales of marketable securities	106,308	169,056	196,865
Purchases of marketable securities	(106,937)	(169,902)	(199,803)
Other investing activities	1,298	939	929
Net cash flows used in investing activities	(104,771)	(78,160)	(49,324)
Financing Activities:			
Cash dividends on common stock	(18,203)	(39,706)	(12,779)
(Decrease)/increase in short-term debt	(29,850)	29,850	-
Issuance of long-term debt	-	-	40,000

Retirements of rate reduction bonds	(14,441)	(13,555)	(12,697)
Increase/(decrease) in NU Money Pool borrowings	104,500	16,700	(15,900)
Capital contributions from NU parent	863	16,281	13,607
Other financing activities	(226)	(3)	(681)
Net cash flows provided by financing activities	42,643	9,567	11,550
Net increase/(decrease) in cash	1	(1,110)	(226)
Cash - beginning of year	-	1,110	1,336
Cash - end of year	$ 1	$ -	$ 1,110

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 Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), and Yankee Gas Services Company (Yankee Gas) (the regulated companies) and NU Enterprises, Inc. (NU Enterprises), as described below. NU was formed on July 1, 1966 when CL&P, WMECO and The Hartford Electric Light Company affiliated under the common ownership of NU. In 1992, PSNH became a subsidiary of NU. 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, was completed. CL&P, PSNH and WMECO are reporting companies under the Securities Exchange Act of 1934. NU is a public utility holding company under the Public Utility Holding Company Act of 2005 (PUHCA). 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 Federal Energy Regulatory Commission (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 their respective 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 1B, "Summary of Significant Accounting Policies - Presentation," 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. Intercompany transactions have been eliminated in consolidation.

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of 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.

In accordance with Financial Accounting Standards Board (FASB) guidance on noncontrolling interests in consolidated financial statements effective January 1, 2009, the Preferred stock of CL&P, which is not owned by NU or its consolidated subsidiaries and is not subject to mandatory redemption, has been presented as a noncontrolling interest in CL&P in the accompanying consolidated financial statements of NU. The Preferred stock of CL&P is considered to be temporary equity and has been classified between liabilities and permanent shareholders' equity on the accompanying consolidated balance sheets of NU and CL&P due to a provision in CL&P's certificate of incorporation that grants preferred stockholders the right to elect a majority of CL&P's board of directors should certain conditions exist, such as if preferred dividends are in arrears for one year. The Net income reported in the accompanying consolidated statements of income and cash flows represents consolidated net income prior to apportionment to noncontrolling interests, which is represented by dividends on preferred stock of CL&P.

The included presentation and disclosure requirements effective January 1, 2009 have been applied retrospectively to the consolidated balance sheet as of December 31, 2008 and the consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the years ended December 31, 2008 and 2007. For the years ended December 31, 2009, 2008 and 2007, there was no change in NU parent's 100 percent ownership of the common equity of CL&P.

Certain other reclassifications of prior period data were made in the accompanying consolidated balance sheets and cash flows for all companies presented as well as in the accompanying consolidated statements of common shareholders' equity and comprehensive income for NU. These reclassifications were made to conform to the current year's presentation.

NU's consolidated statement of income for the year ended December 31, 2007 classifies 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),

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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.).

Included in discontinued operations for the year ended December 31, 2007 is a net gain of $2.1 million related to the favorable resolution of legal and contract issues from businesses sold of $4.2 million, partially offset by a purchase price adjustment of $1.9 million and other charges from the sale of the competitive generation business. Included in the 2007 income tax expense for discontinued operations 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, 2009, 2008 or 2007.

C.

Accounting Standards Issued But Not Yet Adopted

In June 2009, the FASB issued guidance on the consolidation of variable interest entities (VIEs) that requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a VIE. This analysis identifies the party that must consolidate a VIE, referred to as the primary beneficiary, as the enterprise that has both of the following characteristics: (a) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and (b) the obligation to absorb losses of or receive benefits from the entity that could potentially be significant to the VIE. The guidance reduces emphasis on the quantitative analyses for determining the primary beneficiary of a VIE, which was based on identifying which party absorbs the majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both. This guidance is effective as of January 1, 2010, for interim and annual reporting periods beginning in 2010. Earlier application was prohibited. NU, including CL&P, PSNH, and WMECO, does not currently consolidate any VIEs with which the Company is associated and does not expect implementation of this guidance to have a material effect on the accompanying consolidated financial statements.

D.

Accounting Standards Recently Adopted

On January 1, 2009, NU, including CL&P, PSNH and WMECO, adopted fair value measurement guidance for nonrecurring fair value measurements of nonfinancial assets and liabilities, including asset retirement obligations (AROs) and goodwill and other impairment analyses. Implementation of this guidance did not affect the accompanying consolidated financial statements.

In the second quarter of 2009, NU, including WMECO, adopted guidance related to the recognition and presentation of other-than-temporary impairments. This guidance changes the indicators for determining if unrealized losses on debt securities (the excess of amortized cost over fair value) should be recorded in Net income as other-than-temporary impairments. Beginning in the second quarter of 2009, other-than-temporary impairments of debt securities in NU's Trust Under Supplemental Executive Retirement Plan (SERP) (NU supplemental benefit trust) are reflected in the Company's consolidated statement of income if the Company either intends to sell the security or would more likely than not be required to sell the security before recovery of its amortized cost, or if the Company does not expect to recover the amortized cost as a result of a credit loss. For securities that the Company does not intend to sell and it is not more likely than not that it will be required to sell before recovery, only the credit loss component of an impairment is recognized in Net income, and the remainder is recognized in Accumulated other comprehensive income/(loss). NU recorded an after-tax cumulative effect of a change in accounting principle of $0.7 million as an increase to the April 1, 2009 balance of Retained earnings with an offset to Accumulated other comprehensive income/(loss) relating to the reversal of unrealized losses previously recorded in Net income on debt securities held in the NU supplemental benefit trust, which did not meet the criteria described above. The after-tax cumulative effect had a de minimus impact to CL&P, PSNH and WMECO. The guidance had no impact on unrealized losses in WMECO's spent nuclear fuel trust as unrealized losses including impairments are recorded in Deferred debits and other assets - other on the accompanying consolidated balance sheets due to the regulatory accounting treatment of this trust.

In 2009, NU, including CL&P, PSNH and WMECO, adopted guidance regarding subsequent events, which incorporates into FASB authoritative literature accounting guidance that originated as auditing standards about events or transactions that occur after the balance sheet date but before financial statements are issued. This guidance retains the auditing standard requirements to recognize in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed as of the balance sheet date and to disclose but not recognize in the financial statements subsequent events that provide evidence about conditions that arose after the balance sheet date but before the financial statements are issued. In preparing the accompanying consolidated financial statements, NU has evaluated events subsequent to December 31, 2009 through the issuance of the financial statements. See Note 19, "Subsequent Event" for further information.

In the second quarter of 2009, NU, including CL&P, PSNH and WMECO, adopted guidance which clarifies how to estimate fair value when the volume and level of activity for an asset or liability have significantly decreased and how to identify transactions that are not orderly. This guidance requires additional disclosures related to fair value measurements. Implementation of this guidance did not affect the companies' valuation of assets or liabilities that are measured at fair value.

In December 2009, NU, including CL&P, PSNH and WMECO, adopted accounting guidance on measuring liabilities at fair value, which provides guidance on how to measure the fair value of a liability when a quoted price for the liability is not available. The guidance reaffirms existing guidance requiring that fair values reflect the price that NU would expect to pay to transfer the liabilities in the current market. The guidance did not affect the financial statements of NU, CL&P, PSNH, or WMECO upon adoption.

In December 2009, NU, including CL&P, PSNH and WMECO, adopted accounting guidance on using net asset values in determining the fair values of alternative investments. NU holds alternative investments, such as private equity partnerships, real estate partnerships and hedge funds, in its Pension Plan and postretirement benefits other than pension (PBOP) plan. This guidance did not affect the financial statements of NU, CL&P, PSNH or WMECO upon adoption.

E.

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 also utilize regulatory commission-approved tracking mechanisms to recover certain costs as incurred. 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 accounting guidance on reporting realized gains and losses on derivative instruments. Revenues and expenses associated with derivative instruments to purchase and sell energy in the day ahead and real time markets are recorded on a net basis in either Operating revenues or Fuel, purchased and net interchange power on the consolidated statements of income.

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 Operating revenues on the consolidated statements of income and are assets on the consolidated balance sheets 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 refunded to, customers. As of December 31, 2009, the Schedule 21 - NU rates were in a total underrecovery position of $38.8 million ($28.2 million for CL&P, $5.6 million for PSNH and $5 million for WMECO), which will be collected from customers in June 2010.

Regulated Companies' Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, 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: 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 on the consolidated statements of income. 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 probable.

F.

Derivative Accounting

Most of 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 NU Enterprises', through 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.

The application of derivative accounting is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of the "normal purchases or normal sales" (normal) 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 and recorded as a net derivative asset or liability to the consolidated balance sheets.

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The judgment applied in the election of the normal 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 of the underlying product and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. The Company has elected normal on many derivative contracts, including all of WMECO's 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.

Most of the contracts that comprise NU Enterprises' 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. 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 on the consolidated statements of income.

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.

G.

Fair Value Measurements

On January 1, 2008, NU, including CL&P, PSNH, and WMECO, adopted fair value measurement guidance, which established a framework for defining and measuring fair value and required expanded disclosures about fair value measurements.

Upon adoption, the Company applied this guidance to the regulated and unregulated companies' derivative contracts that are recorded at fair value and to the marketable securities held in the NU supplemental benefit trust and WMECO's spent nuclear fuel trust. Fair value measurement guidance also applies to investment valuations used to calculate the funded status of NU's Pension and PBOP plans and non-recurring fair value measurements of NU's non-financial assets and liabilities, such as Yankee Gas goodwill and AROs.

As a result of adoption, the Company recorded a pre-tax charge to Net income of $6.1 million as of January 1, 2008 related to derivative liabilities for its remaining unregulated wholesale marketing contracts. In 2009 and 2008, the Company recorded benefits of $0.7 million and $0.8 million, respectively, to partially reverse the exit price impact recorded as the Company served out rather than exited the contract with the New York Municipal Power Authority (NYMPA). In 2008, the Company also recorded a benefit of $1.8 million related to a contract that expired in May 2008.

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. Accordingly, there was no impact to Net income as a result of these contracts.

The Company measures its derivative instruments that are not designated as normal and marketable securities at fair value.

Fair Value Hierarchy: 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 terms of the contracts. Inputs used in fair value measurements are 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 valuation techniques and inputs used in NU's fair value measurements are as follows:

Derivative instruments: 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 used in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under 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 contracts for differences (CfDs), CL&P's contracts with certain independent power producers (IPPs), PSNH and Yankee Gas physical 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 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.

<u>Marketable securities:</u> NU and WMECO hold in trust marketable securities, which include equity securities, mutual funds and cash equivalents, and fixed income 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 for identical investments are available and used in NU's fair value measurements.

Fixed income 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.

There were no changes to the valuation methodologies for derivative instruments or marketable securities for the years ended December 31, 2009 and 2008.

H.

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.

The transmission and distribution segments of CL&P, PSNH (including its generation business) and WMECO, along with Yankee Gas' distribution segment, continue to be rate-regulated on a cost-of-service basis. Management believes it is probable that NU's regulated companies will recover their respective investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning an equity return, except for the majority of deferred benefit cost assets, regulatory assets offsetting derivative liabilities, securitized regulatory assets and income tax assets, which are not supported by equity. Amortization and deferrals of regulatory assets/(liabilities) are included on a net basis in Amortization of regulatory assets/(liabilities), net on the accompanying consolidated statements of income.

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

	As of December 31,			
		2009		**2008**
(Millions of Dollars)		**NU**		**NU**
Deferred benefit costs	$	1,132.1	$	1,140.9
Regulatory assets offsetting derivative liabilities		855.6		844.2
Securitized assets		432.9		677.4
Income taxes, net		363.2		355.4
Unrecovered contractual obligations		149.5		169.1
Regulatory tracker deferrals		104.1		128.6
Storm cost deferral		60.0		19.3
Conditional asset retirement obligations (Note 1M)		42.9		42.3
Losses on reacquired debt		24.0		26.4
Yankee Gas environmental costs		23.3		25.2
Other regulatory assets		57.3		73.8
Totals	$	3,244.9	$	3,502.6

	As of December 31,					
	2009			2008		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Deferred benefit costs	$ 502.4	$ 154.2	$ 104.9	$ 537.7	$ 142.9	$ 113.5
Regulatory assets offsetting derivative liabilities	828.6	26.4	-	751.9	92.1	-
Securitized assets	195.4	180.1	57.4	377.8	227.6	72.0
Income taxes, net	304.1	21.9	16.9	306.8	16.1	20.7
Unrecovered contractual obligations	118.0	-	31.5	132.6	-	36.5
Regulatory tracker deferrals	70.3	19.0	11.3	113.8	13.3	0.2
Storm cost deferral	-	50.8	9.2	-	8.2	11.1
Conditional asset retirement obligations (Note 1M)	23.8	14.0	2.8	23.1	13.9	2.8
Losses on reacquired debt	12.7	9.2	0.4	14.0	10.1	0.5
Other regulatory assets	13.5	18.5	6.4	16.4	25.7	11.1
Totals	$ 2,068.8	$ 494.1	$ 240.8	$ 2,274.1	$ 549.9	$ 268.4

Additionally, the regulated companies had $27.1 million ($9.9 million for CL&P, zero for PSNH, and $9.1 million for WMECO) and $68.3 million ($5.6 million for CL&P and $62.7 million for PSNH) of regulatory costs as of December 31, 2009 and 2008, respectively, which were included in Deferred debits and other assets - other on the accompanying consolidated balance sheets (refer to Storm Cost Deferral below for further information on balances of PSNH). The $9.1 million for WMECO relates to a reserve established in 2009 for uncollectible hardship accounts receivable. These amounts represent incurred costs that have not yet been approved for recovery by the applicable regulatory agency. Management believes these costs are probable of recovery in future cost-of-service regulated rates.

Deferred Benefit Costs: NU's Pension, SERP, and PBOP Plans are accounted for in accordance with accounting guidance on defined benefit pension and other postretirement plans. Under this accounting guidance, the funded status of its pension and PBOP plans is recorded with an offset to Accumulated other comprehensive income/(loss) and is remeasured annually. However, because the regulated companies are cost-of-service rate-regulated entities, offsets were recorded as regulatory assets as of December 31, 2009 and 2008 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 expected to be amortized into expense over a period of up to 12 years. WMECO's deferred benefit costs are earning an equity return at the same rate as the assets included in rate base.

Regulatory Assets Offsetting Derivative Liabilities: The regulatory assets offsetting derivative liabilities relate to the fair value of contracts used to purchase power and other related contracts that will be collected from customers in the future. Included in these amounts are $768.7 million and $677.8 million as of December 31, 2009 and 2008, 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 and is being recovered as the actual contract costs settle over the duration of the contracts.

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 $167 million and $322.9 million as of December 31, 2009 and 2008, respectively, which includes $23.2 million and $44.9 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 regulatory assets associated with income taxes. The securitized income tax regulatory asset had an unamortized balance of $28.4 million and $54.9 million as of December 31, 2009 and 2008, 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 power contracts with an affiliate, North Atlantic Energy Corporation. In May 2001, WMECO issued $155 million in RRBs and used the majority of the proceeds from that issuance to buyout an IPP contract.

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 and accounting guidance for income taxes. Differences in income taxes between the accounting guidance and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets. For further information regarding income taxes, see Note 1I, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial statements.

Unrecovered Contractual Obligations: Under the terms of contracts with the Connecticut Yankee Atomic Power Company (CYAPC), Yankee Atomic Electric Company (YAEC), and Maine Yankee Atomic Power Company (MYAPC) (Yankee Companies), CL&P, PSNH, and WMECO are responsible for their proportionate share of the remaining costs of the nuclear facilities, including decommissioning. A portion of these amounts was recorded as unrecovered contractual obligations regulatory assets as of December 31, 2009 and 2008. A portion of these obligations for CL&P was securitized in 2001 and was included in securitized regulatory assets. Amounts for CL&P are earning a return and are being recovered through the Competitive Transition Assessment (CTA). Amounts for WMECO are

being recovered without a return along with other stranded costs and are anticipated to be recovered by 2013, the scheduled completion date of stranded cost recovery. Amounts for PSNH were fully recovered by 2006.

Regulatory Tracker Deferrals: Regulatory tracker deferrals are approved restructuring rate mechanisms that allow utilities to recover costs in specific business segments through reconcilable tracking mechanisms that are reviewed at least annually by the applicable regulatory commission. Regulatory tracker deferrals are recorded as regulatory assets if unrecovered costs are in excess of collections and are recorded as regulatory liabilities if collections are in excess of costs. The following regulatory tracker deferrals were recorded as either regulatory assets or liabilities as of December 31, 2009 and 2008:

<u>CL&P Tracker Deferrals</u>: 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. As of December 31, 2009, CL&P's CTA was a $32.2 million regulatory asset, as CTA unrecovered costs were in excess of CTA collections. As of December 31, 2008, CTA collections were in excess of CTA costs, and a $47.7 million regulatory liability was recorded. As part of the CTA reconciliation process, CL&P has also established an obligation to potentially refund the variable incentive portion of its transition service procurement fee, which totaled $23.2 million and $21.8 million as of December 31, 2009 and 2008, respectively, and was recorded as a regulatory liability.

The conservation and load management (C&LM) charge allows CL&P to recover the costs of C&LM programs. C&LM overcollections totaled $32.8 million and were recorded as a regulatory liability as of December 31, 2009 whereas C&LM undercollections totaled $17.6 million and were recorded as a regulatory asset as of December 31, 2008.

The Generation Service Charge (GSC) allows CL&P to recover the costs of the procurement of energy for Standard Service (SS) and Last Resort Service (LRS). The Federally Mandated Congestion Charges (FMCC) mechanism allows CL&P to recover the costs of congestion and other costs associated with power market rules approved by the FERC. As of December 31, 2009 and 2008, CL&P's GSC and FMCC were recorded as a $2.4 million and $31.9 million regulatory asset, respectively, as GSC and FMCC unrecovered costs were in excess of GSC and FMCC collections.

The Systems 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. As of December 31, 2009 and 2008, SBC undercollections totaled $18 million and $43.3 million, respectively, and were recorded as a regulatory asset, as SBC unrecovered costs were in excess of SBC collections.

As of December 31, 2009 and 2008, CL&P retail transmission costs were in excess of collections and $17.7 million and $21 million, respectively, were recorded as a regulatory asset.

<u>PSNH Tracker Deferrals</u>: PSNH recovers the cost of C&LM programs and C&LM overcollections totaled $4.4 million and $4.6 million as of December 31, 2009 and 2008, respectively.

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. As of December 31, 2009, the ES deferral was in an underrecovery position of $8.4 million and was recorded as a regulatory asset whereas the ES deferral was in an overrecovery position of $33 million and was recorded as a regulatory liability as of December 31, 2008.

The Stranded Cost Recovery Charge (SCRC) allows PSNH to recover restructuring costs as a result of deregulation and the Transmission Cost Adjustment Mechanism (TCAM) covers retail transmission costs incurred by PSNH's distribution business. As of December 31, 2009 and 2008, SCRC undercollections totaled $3.9 million and $10.3 million, respectively, and TCAM undercollections totaled $6.7 million and $3 million, respectively.

<u>WMECO Tracker Deferrals</u>: The C&LM charge allows WMECO to recover the costs of C&LM programs. C&LM undercollections totaled $2.5 million and $0.2 million and were recorded as a regulatory asset as of December 31, 2009 and 2008, respectively.

The default service rate allows WMECO to recover the costs of the procurement of energy for basic service. Default service overcollections totaled $2.1 million and $1.3 million and were recorded as a regulatory liability as of December 31, 2009 and 2008, respectively.

As part of a rate case settlement, WMECO's pension and PBOP plan costs have been approved to be recovered through a tracking mechanism beginning 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 deferred future pension and PBOP benefit obligations. As of December 31, 2009, pension/PBOP undercollections totaled $1 million and were recorded as a regulatory asset as the pension/PBOP expenses exceeded the revenue collected from customers. As of December 31, 2008, pension/PBOP overcollections totaled $2 million and were recorded as a regulatory liability.

WMECO recovers its stranded costs through a transition charge. This amount represents the cumulative excess of transition expenses over transition revenues. Transition charge undercollections totaled $6.9 million and were recorded as a regulatory asset as of December 31, 2009. As of December 31, 2008, transition charge overcollections totaled $5.7 million and were recorded as a regulatory liability.

As of December 31, 2009, WMECO retail transmission costs were in excess of collections and $0.9 million was recorded as a regulatory asset. As of December 31, 2008, retail transmission collections were in excess of costs and $0.2 million was recorded as a regulatory liability.

Storm Cost Deferral: The storm cost deferral relates to costs incurred at PSNH and WMECO for restorations that met regulatory agency specified criteria for deferral to a major storm cost reserve. The deferral as of December 31, 2009 relates primarily to $48.1 million of remaining costs incurred at PSNH for a major storm in December 2008. In July 2009, the NHPUC concluded in a temporary rate order that PSNH could begin recovery of these storm costs. These assets are included in rate base. WMECO expects to begin recovery of its deferred storm costs as a result of its next distribution rate proceeding.

Yankee Gas Environmental Costs: The regulatory asset relates to environmental remediation costs at Yankee Gas. The DPUC approved an allowed level of remediation cost recoveries of approximately $2.2 million annually effective July 1, 2007. The DPUC has stated that to the extent that environmental remediation expenses are prudently incurred, they should be allowed as proper operating expenses; therefore, management continues to believe that recording the regulatory asset is appropriate as such costs are probable of recovery.

Losses on Reacquired Debt: The regulatory asset relates to the losses associated with the reacquisition or redemption of long-term debt. These deferred losses are amortized over the life of the new long-term debt issuance.

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

	As of December 31,			
		2009		**2008**
(Millions of Dollars)		**NU**		**NU**
Cost of removal	$	209.2	$	226.0
Regulatory liabilities offsetting derivative assets		109.4		137.8
Regulatory tracker deferrals		62.5		116.2
CL&P AFUDC transmission incentive (Note 1L)		50.4		47.6
Pension and PBOP liabilities -				
Yankee Gas acquisition		15.0		17.6
Overrecovered gas costs		7.1		16.9
Other regulatory liabilities		32.1		30.4
Totals	$	485.7	$	592.5

	As of December 31,					
	2009			2008		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Cost of removal	$ 82.2	$ 60.5	$ 16.6	$ 91.2	$ 64.7	$ 19.2
Regulatory liabilities offsetting derivative assets	109.0	0.4	-	131.3	4.6	-
Regulatory tracker deferrals	56.0	4.4	2.1	69.5	37.6	9.1
CL&P AFUDC transmission incentive (Note 1L)	50.4	-	-	47.6	-	-
WMECO provision for rate refunds	-	-	2.0	-	-	1.3
Other regulatory liabilities	18.6	4.6	1.0	23.9	4.5	0.2
Totals	$ 316.2	$ 69.9	$ 21.7	$ 363.5	$ 111.4	$ 29.8

Cost of Removal: NU's regulated companies currently recover amounts in rates for future costs of removal of plant assets over the lives of the assets. These amounts are classified as Regulatory liabilities on the accompanying consolidated balance sheets. This liability is included in rate base.

Regulatory Liabilities Offsetting Derivative Assets: The regulatory liabilities offsetting derivative assets relate to the fair value of contracts used to purchase power and other related contracts that will benefit ratepayers in the future. See Note 3, "Derivative Instruments," to the consolidated financial statements for further information. This liability is excluded from rate base and is refunded as the actual contract costs settle over the duration of the contracts.

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. The pension and PBOP liabilities were approved for amortization over an approximate 13- and 6-year period, respectively, beginning in 2002 without a return on the liabilities. The PBOP liability was fully amortized as of February 2009.

Overrecovered Gas Costs: The Purchased Gas Adjustment (PGA) clause allows Yankee Gas to recover the costs of the procurement of gas for Yankee Gas' firm and seasonal customers. Differences between actual gas costs and collection amounts on August 31st of each year are deferred and then recovered or returned to customers during the following year. Carrying charges on outstanding balances are calculated using Yankee Gas' weighted average cost of capital in accordance with the directives of the DPUC.

WMECO Provision for Rate Refunds: The provision for rate refunds was established to reserve a refund to customers as a result of DPU service quality penalty guidelines.

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Income Taxes

The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and relevant accounting guidance. Details of income tax expense related to continuing operations are as follows:

	For the Years Ended December 31,		
	2009	**2008**	**2007**
	NU	**NU**	**NU**
(Millions of Dollars)			
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	$ 4.5	$ 6.0	$ 89.3
State	52.7	16.3	18.9
Total current	57.2	22.3 &n	