CONNECTICUT LIGHT & POWER CO
Form 10-K
February 24, 2012

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, 2011
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	02-0181050

Manchester, New Hampshire 03101-1134
Telephone: (603) 669-4000

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

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 whether the registrants have submitted electronically and posted on its corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

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, 2011) was **$6,218,948,649** based on a closing sales price of **$35.17** per share for the 176,825,381 common shares outstanding on June 30, 2011. **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 issuers' classes of common stock, as of the latest practicable date:

Company - Class of Stock	Outstanding as of January 31, 2012
Northeast Utilities	
Common shares, $5.00 par value	177,203,768 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

GLOSSARY OF TERMS

The following is a glossary of 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 the Holyoke Water Power Company
NGS	Northeast Generation Services Company and subsidiaries
NPT	Northern Pass Transmission LLC, a jointly owned limited liability company, held by NUTV and NSTAR Transmission Ventures, Inc. on a 75 percent and 25 percent basis, respectively
NUTV	NU Transmission Ventures, Inc.
NU or the Company	Northeast Utilities and subsidiaries
NU Enterprises	NU Enterprises, Inc., the parent company of Select Energy, NGS, NGS Mechanical, Select Energy Contracting, Inc. and Boulos
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, RRR (a real estate subsidiary), 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 activities of PSNH and WMECO, Yankee Gas, a natural gas local distribution company, and NPT
RRR	The Rocky River Realty Company
Select Energy	Select Energy, Inc.
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS:

DEEP	Connecticut Department of Energy and Environmental Protection
DOE	U.S. Department of Energy
DPU	Massachusetts Department of Public Utilities
DPUC	Connecticut Department of Public Utility Control
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission
PURA	Connecticut Public Utility Regulatory Authority (formerly DPUC)
SEC	Securities and Exchange Commission

OTHER:

2010 Healthcare Act	Patient Protection and Affordable Care Act

AOCI	Accumulated Other Comprehensive Income/(Loss)
AFUDC	Allowance For Funds Used During Construction
AMI	Advanced metering infrastructure
ARO	Asset Retirement Obligation
C&LM	Conservation and Load Management
CERLA	The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980
CfD	Contract for Differences
CO_2	Carbon dioxide
CTA	Competitive Transition Assessment
CWIP	Construction work in progress
CYAPC	Connecticut Yankee Atomic Power Company
DOER	Massachusetts Department of Energy Resources
EIA	Energy Independence Act
EMF	Electric and Magnetic Fields
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights

GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse Gas
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Giga-watt Hours
HG&E	Holyoke Gas and Electric, a municipal department of the town of Holyoke, MA
HQ	Hydro-Québec, a corporation wholly owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High voltage direct current
Hydro Renewable Energy	H.Q. Hydro Renewable Energy, Inc., a wholly owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE	ISO New England, Inc., the New England Independent System Operator
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
KV	Kilovolt
kWh	Kilowatt-Hours
LNG	Liquefied natural gas
LOC	Letter of Credit
LRS	Supplier of last resort service
MGP	Manufactured Gas Plant
Millstone	Millstone Nuclear Generating station, made up of Millstone 1, Millstone 2, and Millstone 3. All three units were sold in March 2001.
Money Pool	Northeast Utilities Money Pool
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
MYAPC	Maine Yankee Atomic Power Company
NEEWS	New England East-West Solution
NO_x	Nitrogen oxide
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NPDES	National Pollutant Discharge Elimination System
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
OCI	Other Comprehensive Income
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan that provides certain retiree health care benefits, primarily medical and dental, and life insurance benefits
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PGA	Purchased Gas Adjustment
PPA	Pension Protection Act
RECs	Renewable Energy Certificates
Regulatory ROE	

	The average cost of capital method for calculating the return on equity related to the distribution and generation business segment excluding the wholesale transmission segment
RGGI	Regional Greenhouse Gas Initiative
RNS	Regional Network Service
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide
SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company
WWL Project	The construction of a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of Yankee Gas' LNG plant
YAEC	Yankee Atomic Electric Company
Yankee Companies	Connecticut Yankee Atomic Power Company, Yankee Atomic Electric Company and Maine Yankee Atomic Power Company

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

2011 Form 10-K Annual Report

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THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

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

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

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions 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 simil 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 and taxing 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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actions of rating agencies;

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the expected timing and likelihood of completion of the pending merger with NSTAR, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the pending merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, as well as the ability to successfully integrate the businesses, and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect; and

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other presently unknown or unforeseen factors.

Other risk factors are detailed in our reports filed with the SEC and updated as necessary, and we encourage you to consult such disclosures.

All such factors are difficult to predict, contain uncertainties that 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 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

Please refer to the Glossary of Terms for definitions of defined terms and abbreviations used in this Annual Report on Form 10-K.

PENDING MERGER WITH NSTAR

On October 18, 2010, NU and NSTAR announced that each company s Board of Trustees unanimously approved a Merger Agreement (the agreement), under which NSTAR will become a direct wholly owned subsidiary of NU. On October 14, 2011, NU and NSTAR extended the Termination Date of the agreement, as defined therein, from October 16, 2011 to April 16, 2012. The transaction is structured as a merger of equals in a tax-free exchange of shares. Under the terms of the agreement, NSTAR shareholders will receive 1.312 NU common shares for each NSTAR common share that they own (the exchange ratio). Following the merger, NU will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire. On March 4, 2011, NU shareholders approved the agreement, approved an increase in the number of NU common shares authorized for issuance by 155 million common shares to 380 million common shares and fixed the number of trustees at 14. NSTAR shareholders approved the agreement on March 4, 2011.

Subject to the conditions in the agreement, our first quarterly dividend per common share paid after the closing of the merger will be increased to an amount that is at least equal, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing.

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. NU and NSTAR are awaiting approvals from PURA and the DPU.

In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned PURA to reconsider its earlier conclusion that it lacked jurisdiction to review the merger. On June 1, 2011, PURA declined to change its conclusion that it lacked jurisdiction over the merger. However, on January 18, 2012, PURA issued a decision that revised its June 1, 2011 decision. The January 18, 2012 decision ruled that NU and NSTAR must seek approval from PURA pursuant to Connecticut law prior to completing the merger. NU and NSTAR filed an application with PURA seeking approval of the merger on January 19, 2012. Hearings began February 14, 2012 and PURA is scheduled to issue a final decision on April 2, 2012.

On November 24, 2010, NU and NSTAR filed a joint petition requesting the DPU s approval of the merger and filed supplemental testimony and a net benefit analysis with the DPU on April 8, 2011, in response to the DPU s revision of its merger standard to a net benefits standard. On February 15, 2012, NU and NSTAR reached comprehensive merger-related settlement agreements with both the Massachusetts DOER and the Massachusetts AG. The first settlement agreement was reached with both the AG and the DOER and covers a variety of rate-making and rate design issues, including a distribution rate freeze until 2016 for NSTAR Electric Company, NSTAR Gas Company and WMECO. The second settlement agreement was reached with the DOER and covers a variety of matters impacting the advancement of Massachusetts clean energy goals established by the Green Communities Act and Global Warming Solutions Act.

Pursuant to the terms and provisions of the settlement agreements, the parties agree that the proposed merger between NU and NSTAR is consistent with the public interest and should be approved by the DPU. However, the settlement agreements allow the Attorney General and DOER to terminate their respective agreements for any reason at any time prior to approval by the DPU. All parties have requested that the DPU approve the merger on April 4, 2012. If both the DPU and PURA issue acceptable decisions by that date, we expect the merger will be consummated by April 16, 2012.

All other approvals required to consummate the merger have been received. For further information regarding regulatory approvals on the pending merger, see Regulatory Developments and Rate Matters Regulatory Approvals for Pending Merger with NSTAR, in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations,* in this Annual Report on Form 10-K.

THE COMPANY

NU, headquartered in Hartford, Connecticut, is a public utility holding company subject to regulation by 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 that serves residential, commercial and industrial customers in parts of Connecticut;

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

Western Massachusetts Electric Company (WMECO), a regulated electric utility that serves residential, commercial and industrial customers in parts of western Massachusetts and owns solar generating assets; and

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

NU also owns certain unregulated businesses through its wholly owned subsidiary, NU Enterprises, which are included in its Parent and other companies results of operations.

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 distribution segment (which also includes the generation businesses of PSNH and WMECO and our natural gas distribution business) and the transmission segment. Our distribution segment represented approximately 53 percent of our Regulated companies earnings and our electric transmission segment represented approximately 47 percent.

REGULATED ELECTRIC DISTRIBUTION

General

NU s electric distribution segment consists of the distribution businesses of CL&P, PSNH and WMECO, which are engaged in the distribution of electricity to retail customers in Connecticut, New Hampshire and western Massachusetts, respectively, plus the regulated electric generation businesses of PSNH and WMECO. The following table shows the sources of 2011 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	58
Commercial	33
Industrial	7
Other	2

Total	100%

A summary of changes in the electric distribution companies retail electric sales (GWh) for 2011, as compared to 2010, on an actual and weather normalized basis (using a 30-year average) is as follows:

	2011	2010	Percentage Decrease	Weather Normalized Percentage Decrease
Residential	14,766	14,913	(1.0)%	(0.2)%
Commercial	14,301	14,506	(1.4)%	(0.3)%
Industrial	4,418	4,481	(1.4)%	(0.2)%
Other	327	330	(1.0)%	(1.0)%
Total	33,812	34,230	(1.2)%	(0.3)%

Actual retail electric sales for all three electric companies were lower in 2011 compared to 2010 due primarily to milder weather in the summer of 2011, compared to warmer than normal weather in the summer of 2010. In 2011, cooling degree days in Connecticut and western Massachusetts were 20.9 percent lower than 2010, and in New Hampshire, cooling degree days were 23.7 percent lower than 2010.

On a weather-normalized basis, total retail electric sales decreased slightly in 2011, as compared to 2010. We believe the weather-normalized commercial sales for CL&P and WMECO decreased in 2011, compared to 2010, due to the slow economic recovery in these service areas. PSNH commercial sales increased in 2011 due to one large self-generating customer who experienced multiple generation outages and relied on PSNH for energy. Industrial sales for both CL&P and WMECO decreased in 2011, compared to 2010, due in part to weak manufacturing activity in Connecticut and western Massachusetts. Our commercial and industrial electric sales continue to be negatively impacted by utilization of distributed generation and conservation programs.

Major Storms

On August 28, 2011, Tropical Storm Irene caused extensive damage to our distribution system resulting in incremental restoration costs of $135.6 million. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut.

On October 29, 2011, an unprecedented autumn snowstorm inundated our service territory with heavy snow, causing significant damage to our distribution and transmission systems resulting in incremental restoration costs of $218.5 million. Approximately 1.2 million of our electric distribution customers were without power at the peak of the outages, with approximately 810,000 of those customers in Connecticut, approximately 237,000 of those customers in

New Hampshire, and approximately 140,000 of those customers in Massachusetts. In terms of customer outages, this was the most severe storm in CL&P s history, surpassing Tropical

Storm Irene; the third most severe in PSNH s history, following a December 2008 ice storm and a February 2010 winter storm; and the most severe in WMECO's history.

CL&P recorded a pre-tax charge for a storm fund reserve of $30 million, in the fourth quarter of 2011, to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011 as a result of the October snowstorm, and to provide contributions to certain Connecticut charitable organizations. Approximately $27 million of the storm fund reserve was used to provide a one-time credit on the February 2012 bills of approximately 192,000 CL&P customers and approximately $3 million was paid to charitable organizations in December 2011. CL&P will not seek to recover this amount in its rates.

Estimated incremental restoration costs related to the two storms are summarized in the table below and consist of costs that are deferred for future recovery and costs that are capitalized:

	For the Year Ended December 31, 2011					
(Millions of Dollars)	**Deferred for Future Recovery**		**Capitalized**		**Total Incremental Costs**	
Tropical Storm Irene:						
CL&P	$	105.6	$	18.2	$	123.8
PSNH		7.0		1.1		8.1
WMECO		3.2		0.5		3.7
Total Tropical Storm Irene		115.8		19.8		135.6
October Snowstorm:						
CL&P		157.7		16.9		174.6
PSNH		14.7		2.2		16.9
WMECO		23.5		3.5		27.0
Total October Snowstorm		195.9		22.6		218.5
Total Storm Costs	$	311.7	$	42.4	$	354.1

We believe our response to both storms was prudent and therefore we believe it is probable that CL&P, PSNH and WMECO will be allowed to recover these storm costs. Each operating company will seek recovery of its estimated deferred storm costs through its applicable regulatory recovery process. For further information regarding various reviews on storm response and preparedness, see Regulatory Developments and Rate Matters 2011 Major Storms, in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* in this Annual Report on Form 10-K.

THE CONNECTICUT LIGHT AND POWER COMPANY - DISTRIBUTION

CL&P s distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2011, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 cities and towns in Connecticut. CL&P does not own any electric generation facilities.

The following table shows the sources of CL&P s 2011 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	59
Commercial	32
Industrial	6
Other	3
Total	100%

Rates

CL&P is subject to regulation by PURA, 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, CTA, SBC and other charges that are assessed on all customers.

The CTA is a charge assessed to recover stranded costs associated with electric industry 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 industry restructuring. The CTA and SBC are annually reconciled to actual costs incurred, with any difference refunded to, or recovered from, customers.

Under Connecticut law, all of CL&P's customers are entitled to choose their energy suppliers, while CL&P remains their electric distribution company. Under SS rates for customers with less than 500 kilowatts of demand and LRS rates for customers with 500 kilowatts of demand or greater, CL&P purchases power for those customers who do not choose a competitive energy supplier and passes the cost to such customers through a combined GSC and FMCC charge on customers' bills. The combined GSC and FMCC

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charges for both types of service recover all of CL&P s costs of procuring energy from wholesale suppliers and are adjusted periodically and reconciled semi-annually in accordance with the directives of PURA.

CL&P continues to supply approximately 35 percent of its customer load at SS or LRS rates while the other 65 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on CL&P s delivery business or its operating income.

Distribution Rates: On June 30, 2010, PURA issued a final order in CL&P s most recent retail distribution rate case approving annualized distribution rate increases of $63.4 million effective July 1, 2010 and an incremental $38.5 million effective July 1, 2011. The 2010 increase was deferred from customer bills until January 1, 2011 to coincide with the decline in revenue requirements associated with the final payment of CL&P s RRBs. In its decision, PURA also maintained CL&P s authorized distribution segment regulatory ROE of 9.4 percent. In 2011, CL&P earned a distribution segment regulatory ROE of 9.4 percent, compared to 7.9 percent in 2010.

AMI: On August 29, 2011, PURA issued a draft decision rejecting the full deployment of AMI meters to all of CL&P s customers at that time. PURA instead indicated that CL&P should begin installing AMI meters at a more moderate pace once industry standards are developed and CL&P has selected a specific technology to install. On September 2, 2011, the Commissioner of DEEP filed a motion with PURA to suspend the proceeding while the Bureau of Energy and Technology Policy conducts a process to establish an AMI policy for Connecticut, in accordance with the state law. On September 8, 2011, PURA granted DEEP s motion and suspended its proceedings. No further schedule is available at this time from either DEEP or PURA. As a result, CL&P has removed the projected AMI capital costs of approximately $257 million from its current five-year capital program.

CL&P has a transmission adjustment clause as part of its retail distribution 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.

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

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases energy to serve its SS and LRS loads from a variety of competitive sources through periodic requests for proposals. CL&P enters into supply contracts for SS periodically for periods of up to three years to mitigate the risks associated with energy price volatility for its residential and small and medium load commercial and industrial customers. CL&P enters into supply contracts for LRS for larger commercial and industrial customers every three months. Currently, CL&P has contracts in place with various suppliers for all of its SS loads through 2012, and 40 percent of expected load for 2013. CL&P s contracts for its LRS loads extend through the second quarter of 2012.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE - DISTRIBUTION

PSNH s distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2011, PSNH furnished retail franchise electric service to approximately 498,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of primarily fossil fueled electricity generation plants. Included in those electric generating plants is PSNH s 50 MW wood-burning Northern Wood Power Project at its Schiller Station in Portsmouth, New Hampshire, and approximately 70 MW of hydroelectric generation. PSNH s distribution segment includes the activities of its generation business.

The Clean Air Project, a wet scrubber project, was constructed and placed in service by PSNH at its Merrimack Station in September 2011. The cost of the project will be recovered through PSNH's ES rates under New Hampshire law. By November 2011, both of Merrimack station s coal-fired units were integrated with the scrubber, and the scrubber is now reducing emissions from the units. PSNH expects to complete remaining project construction activities in mid-2012. We currently expect the final costs of the project to be approximately $422 million**.**

The following table shows the sources of PSNH s 2011 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	54
Commercial	35
Industrial	8
Other	3
Total	100%

Rates

PSNH is subject to regulation by the 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 ES rate recovers its generation and purchased power costs from customers on a current basis and allows for an ROE of 9.81 percent on its generation investment.

Under New Hampshire law, the SCRC allows PSNH to recover its stranded costs, including above-market expenses incurred under mandated power purchase obligations 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. PSNH recovers the costs of these RRBs through the SCRC rate. The amount of the RRB obligation decreases each quarter and the RRBs are scheduled to be retired as of May 1, 2013.

On an annual basis, PSNH files with the NHPUC an ES/SCRC cost reconciliation filing for the preceding year. The difference between revenues and costs are included in the ES/SCRC rate calculations and refunded to or recovered from customers in the subsequent period approved by the NHPUC.

The TCAM allows PSNH to recover on a fully reconciling basis its transmission related costs. The TCAM is adjusted on July 1 of each year.

Distribution Rates: On June 28, 2010, the NHPUC approved a joint settlement of PSNH s rate case allowing a net distribution rate increase of $45.5 million on an annualized basis effective July 1, 2010, an annualized distribution rate decrease of $2.4 million effective July 1, 2011 and projected increases of $9.5 million and $11.1 million on July 1, 2012 and 2013, respectively. If PSNH s 12-month trailing average regulatory ROE is greater than 10 percent, amounts over the 10 percent level will be allocated 75 percent to customers and 25 percent to PSNH. The settlement also provided that the authorized regulatory ROE on distribution only plant will continue at the previously allowed level of 9.67 percent. PSNH s distribution segment regulatory ROE was 9.7 percent (including generation) in 2011, compared to 10.2 percent in 2010.

In March 2011, PSNH filed with the NHPUC to collect certain exogenous costs, step increases, and storm costs, as permitted by its 2010 rate case settlement. These rate increases were offset by the scheduled termination, on June 30, 2011, of a rate recoupment charge, also from the 2010 rate case settlement. During the second quarter of 2011, the NHPUC issued rate orders approving net increases in revenue requirements effective July 1, 2011 to (1) recover exogenous costs, (2) implement a step increase program for capital additions and the reliability enhancement program, and (3) allow for the recovery of the 2010 windstorm costs. Together with the scheduled termination of the rate recoupment charge, the net impact of these rate changes was a $2.4 million decrease in rates effective July 1, 2011.

Under New Hampshire law, all of 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, customer migration levels began to increase significantly in 2009 as energy costs decreased from their historic high levels and competitive energy suppliers with more pricing flexibility were able to offer electricity supply at lower prices than PSNH. By the end of 2011, approximately 2.6 percent of all of PSNH s customers (approximately 36 percent of load), mostly large commercial and industrial customers, had switched to competitive energy suppliers. The increased level of migration has caused an increase in the ES rate, as fixed costs of PSNH s generation assets must be spread over a smaller group of customers and lower sales volume. The customers that did not choose a third party supplier, predominately residential and small commercial and industrial customers, are now paying a larger proportion of these fixed costs. On July 26, 2011, the NHPUC ordered PSNH to file a rate proposal that would mitigate the impact of customer migration expected to occur when the ES rate is higher than market prices. On January 26, 2012, the NHPUC rejected the PSNH proposal and ordered PSNH to file a new proposal, no later than June 30, 2012, addressing certain issues raised by the NHPUC.

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

On November 22, 2011, the NHPUC opened a docket to consider the in-service status of the Clean Air Project, the appropriate rate treatment, PSNH s prudence in construction of the project and the propriety of setting temporary rates. Hearings on temporary rates are scheduled for March 12 and 13, 2012. Following hearings on temporary rates, it is expected that recovery of costs of the Clean Air

Project will begin during the second quarter of 2012. No formal schedule for the comprehensive prudence review or for permanent rates has been established.

Sources and Availability of Electric Power Supply

During 2011, approximately 72 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 28 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 2012 in a similar manner. Included in the 72 percent above are PSNH obligations to purchase power from approximately two dozen IPPs, the output of which it either uses to serve its customer load or sells into the ISO-NE market.

WESTERN MASSACHUSETTS ELECTRIC COMPANY - DISTRIBUTION

WMECO s distribution business consists primarily of the purchase, delivery and sale of electricity to residential, commercial and industrial customers. As of December 31, 2011, WMECO furnished retail franchise electric service to approximately 206,000 retail customers in 59 cities and towns in the western region of Massachusetts. WMECO does not own any fossil or hydro-electric generating facilities and purchases its energy requirements from competitive suppliers. In 2009, pursuant to the Massachusetts Green Communities Act, WMECO was authorized to install 6 MW of solar energy generation in its service territory. In October 2010, WMECO completed development of a 1.8 MW solar generation facility on a site in Pittsfield, Massachusetts and in December 2011 completed development of a 2.3 MW solar generation facility in Springfield, Massachusetts. WMECO is continuing to evaluate sites suitable for development of the remaining 1.9 MW of the authorized 6 MW of capacity. WMECO will sell all energy and other products from its solar generation facilities into the ISO-NE market.

The following table shows the sources of WMECO s 2011 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	57
Commercial	34
Industrial	11
Other	(2)
Total	100%

Rates

WMECO is subject to regulation by the 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 recover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under Massachusetts law, all of WMECO's customers are entitled to choose their energy suppliers, while WMECO remains their distribution company. WMECO purchases power from competitive suppliers 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 small commercial and industrial customers have continued to buy their power from WMECO at basic service rates. A greater proportion of large commercial and industrial customers have switched to a competitive energy supplier.

WMECO continues to supply approximately 53 percent of its customer load at basic service rates while the other 47 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on WMECO s delivery business or its operating income.

The DPU has approved a number of individual cost and revenue requirement recovery mechanisms over the years. These individual mechanisms recover costs associated with providing energy, retail transmission of energy, administrative costs to procure energy, bad debt costs associated with providing energy, company investments in renewable energy such as solar generation, and credits given to customers who generate renewable energy. There is also a mechanism for the recovery of stranded generation costs as a result of the 1999 electric restructuring act in Massachusetts. Additionally the DPU has provided cost and revenue requirement recovery mechanisms for certain operating expenses. These individual mechanisms include recovery of employee pension and post-retirement health benefit costs, certain state government regulatory review, energy efficiency programs, customer arrearage forgiveness programs and low income customer discounts. In WMECO s January 31, 2011 rate decision, WMECO received approval for a revenue decoupling reconciliation mechanism that provides assurance that WMECO will recover a DPU pre-established level of baseline distribution delivery service revenue to manage all other distribution operating expenses and earn a level of return on its capital investment. The reconciliation mechanisms noted above are trued up on an annual basis producing deferrals for future recovery.

Distribution Rates: On January 31, 2011, the DPU issued a final decision in WMECO s July 2010 rate application, authorizing a $16.8 million annualized rate increase in distribution revenues and an allowed regulatory ROE of 9.6 percent effective February 1, 2011. The DPU also authorized WMECO s request to recover certain active hardship account balances, the recovery of certain storm costs over five years and a full decoupling mechanism, whereby actual revenue billed by WMECO is reconciled with WMECO s target revenue on an annual basis. The DPU did not authorize rate recovery of a proposed $20 million average increase in WMECO s capital spending plan. WMECO s distribution segment regulatory ROE was 9 percent in 2011, compared to 4.6 percent in 2010.

WMECO is subject to service quality (SQ) metrics that measure safety, reliability and customer service, and WMECO pays any charges incurred for failure to meet such metrics to customers. WMECO will not be required to pay an assessment charge for its 2011 performance results as WMECO performed at or above its target for all of its SQ metrics in 2011.

Sources and Availability of Electric Power Supply

As noted above, WMECO does not own any generation assets (other than its recently developed solar generation) and purchases its energy requirements from a variety of competitive sources through requests for proposals issued periodically, consistent with DPU regulations. WMECO enters into supply contracts for basic service for 50 percent of its residential and small commercial and industrial customers twice a year for twelve month terms. WMECO enters into supply contracts for basic service for 100 percent of large commercial and industrial customers every three months.

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 208,000 customers in 71 cities and towns), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in 2011 was approximately 55 Bcf. Yankee Gas provides firm natural gas sales service to retail customers who require a continuous natural gas supply throughout the year, such as residential customers who rely on gas for heating, hot water and cooking needs, and commercial and industrial customers who choose to purchase natural gas from Yankee Gas. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which is used primarily to assist it in meeting its supplier-of-last-resort obligations and also enables it to make economic purchases of natural gas, which typically occur during periods of low demand.

Retail natural gas service in Connecticut is partially unbundled: residential customers in Yankee Gas service territory buy gas supply and delivery only from Yankee Gas while commercial and industrial customers may choose their gas suppliers. Yankee Gas 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 commercial and industrial customers that have the capability to switch from natural gas to an alternative fuel on short notice, for whom Yankee Gas can interrupt service during peak demand periods or at any other time to maintain distribution system integrity.

The following table shows the sources of 2011 natural gas operating revenues based on categories of customers:

Sources of Revenue	**% of Total Revenues**
Residential	50
Commercial	30
Industrial	17
Other	3
Total	100%

A summary of firm natural gas sales in million cubic feet for Yankee Gas for 2011 and 2010 and the percentage changes in 2011, as compared to 2010 on an actual and weather normalized basis (using a 30-year average) is as follows:

	For the Year Ended December 31, 2011 Compared to 2010			
	Sales (million cubic feet) (1)			**Weather Normalized Percentage Increase/**
Firm Natural Gas	**2011**	**2010**	**Percentage Increase**	**(Decrease)**
Residential	13,508	13,403	0.8%	(3.2)%
Commercial	17,175	15,137	13.5%	9.8%
Industrial	16,197	14,866	8.9%	8.0%
Total	46,880	43,406	8.0%	5.1%
Total, Net of Special Contracts (2)	38,197	35,038	9.0%	5.4%

(1)

The 2010 sales volumes for commercial customers have been adjusted to conform to current year presentation.

(2)

Special contracts are unique to the customers who take service under such an arrangement and generally specify the amount of distribution revenue to be paid to Yankee Gas regardless of the customers usage.

Our firm natural gas sales are subject to many of the same influences as are our retail electric sales, but have benefitted from migration of interruptible customers switching to firm service rates and the addition of gas-fired distributed generation in Yankee Gas' service territory. Actual firm natural gas sales in 2011 were 8 percent higher than 2010. Colder weather, especially in the first quarter of 2011,

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was a contributing factor to the higher sales. Heating degree days for 2011 in Connecticut were 6.4 percent higher than 2010. On a weather normalized basis, actual firm natural gas sales in 2011 were 5.1 percent higher than 2010.

In November 2011, Yankee Gas completed construction of its WWL project, a 16-mile natural gas pipeline between Waterbury and Wallingford, Connecticut and an increase of vaporization output of its LNG plant. Construction on the project began in April 2010 and total costs were approximately $54 million.

Rates

Yankee Gas is subject to regulation by PURA, 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, affiliate transactions, management efficiency and construction and operation of distribution, production and storage facilities.

Distribution Rates: On June 29, 2011 PURA issued a final decision in Yankee Gas rate proceeding, which it amended in September 2011. The final amended decision approved a regulatory ROE of 8.83 percent, based on a capital structure of 52.2 percent common equity and 47.8 percent debt, approved the inclusion in rates of costs associated with the WWL project, and also allowed for a substantial increase in annual spending for bare steel and cast iron pipe replacement, as requested by Yankee Gas. Yankee Gas regulatory ROE was 9.3 percent in 2011, as compared to 8.6 percent in 2010.

Sources and Availability of Natural Gas Supply

PURA requires that Yankee Gas meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its supply portfolio to meet firm 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 also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which is used primarily to assist the company in meeting its supplier-of-last-resort obligations and also enables Yankee Gas to make economic purchases of natural gas, typically in periods of low demand. 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 capacity from the three interstate pipelines that directly 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, Iroquois Gas Transmission Pipeline, Algonquin Pipeline, Union Gas Limited, Dominion Transmission, Inc., National Fuel Gas Supply Corporation, Transcontinental Gas Pipeline Company, and Texas Eastern Transmission, L.P. pipelines. Yankee Gas considers these transportation arrangements adequate for its needs.

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 of all market participants, has served since 2005 as the regional transmission organization of the New England transmission system. ISO-NE works to ensure the reliability of the system, administers, subject to FERC approval, the independent system operator tariff, oversees the efficient and competitive functioning of the regional wholesale power market and determines which costs of all regional major transmission facilities are shared by consumers throughout New England.

Wholesale Transmission Rates

Wholesale transmission revenues are recovered through formula rates that are approved by the FERC. Our transmission revenues are recovered from New England customers through charges that recover costs of transmission and other transmission-related services provided by all regional transmission owners, with a portion of those revenues collected from the distribution segments of CL&P, PSNH and WMECO. These rates provide for the annual reconciliation and recovery or refund of estimated costs to actual costs. The difference between estimated and actual costs is deferred for future recovery from, or refunded to, transmission customers.

FERC ROE Proceedings

Pursuant to a series of orders involving the ROE for regionally planned New England transmission projects, the FERC set the base ROE at 11.14 percent and approved incentives that increased the ROE to 12.64 percent for those projects that were in-service by the end of 2008. Beginning in 2009, the ROE for all regional transmission investment approved by ISO-NE is 11.64 percent, which includes the 50 basis points for joining the regional transmission organization. In addition, certain projects were granted additional ROE incentives by FERC under its transmission incentive policy. As a result, CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects and WMECO earns 12.89 percent on the Massachusetts portion of GSRP. All appeals of FERC's incentive ROE orders for New England transmission owners have been denied.

On September 30, 2011, several New England state attorneys general, state regulatory commissions, consumer advocates and other parties filed a joint complaint with the FERC under Sections 206 and 306 of the Federal Power

Act alleging that the base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by New England transmission

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owners, including CL&P, PSNH and WMECO, is unjust and unreasonable. The complainants asserted that the current 11.14 percent rate, which became effective in 2006, is excessive due to changes in the capital markets, and seek an order to reduce the rate to 9.2 percent, effective September 30, 2011.

On October 20, 2011, the New England transmission owners responded to the complaint, asking FERC to dismiss the complaint on the basis that the complainants failed to carry their burden of proof under Section 206 of the Federal Power Act to demonstrate that the existing base ROE is unjust and unreasonable. The New England transmission owners included testimony and analysis reflecting a base ROE of 11.2 percent using FERC s methodology and precedents, which they believe demonstrates that the current base ROE of 11.14 percent remains just and reasonable.

As of December 31, 2011, CL&P, PSNH, and WMECO had approximately $1.5 billion of aggregate shareholder equity invested in their transmission facilities. As a result, each 10 basis point change in the authorized base ROE would change annual consolidated earnings by approximately $1.5 million.

FERC has not issued an order in this proceeding and NU cannot predict when this proceeding will be concluded, the outcome of this proceeding, or its impact on NU s financial position, results of operations or cash flows.

Transmission Projects

NEEWS

CL&P and WMECO are continuing to develop and construct the NEEWS project, which is comprised of GSRP, the Interstate Reliability Project and the Central Connecticut Reliability Project, and is estimated to cost $1.3 billion in the aggregate.

CL&P and WMECO commenced substation construction on GSRP, the largest project in NEEWS, in December 2010 and began full construction in Connecticut and Massachusetts in late 2011. GSRP was approximately 50 percent complete as of December 31, 2011 and we expect it to be placed in service in late 2013 at a cost of approximately $718 million.

CL&P is designing and building the Interstate Reliability Project in coordination with National Grid USA, whose segment of this phase will interconnect with CL&P s at the Connecticut-Rhode Island border. In August 2010, ISO-NE reaffirmed the need for the Interstate Reliability Project. CL&P filed its siting applications in late 2011 and approvals are expected in late 2013, with construction commencing in late 2013 or early 2014. We expect the project will be placed in service in late 2015 and that CL&P's share of the costs will be $218 million.

The Central Connecticut Reliability Project, which involves construction of a new 345 KV overhead line from Bloomfield, Connecticut to Watertown, Connecticut at a cost of $301 million, is the third major part of NEEWS. In March 2011, ISO-NE announced that it would review the Central Connecticut Reliability Project along with other central Connecticut projects as part of a study known as the Greater Hartford Central Connecticut Study. We expect ISO-NE to issue preliminary need results and transmission solutions in 2013.

Included as part of NEEWS are expenditures for associated reliability related projects, all of which have received siting approval and most of which are under construction. These projects began going into service in 2010 and will continue to go into service through 2013.

Northern Pass Transmission Line Project

NPT is a limited liability company jointly owned by NU and NSTAR to construct, own and operate the Northern Pass transmission line, a planned HVDC transmission line from the Québec-New Hampshire border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire. Northern Pass will interconnect at the Québec/New Hampshire border with a planned HVDC transmission line being developed by HQ. NUTV, a subsidiary of NU, holds a 75 percent interest in NPT, with NSTAR Transmission Ventures, Inc., a subsidiary of NSTAR, holding the remaining 25 percent. We currently estimate that our 75 percent share of the costs to build the Northern Pass transmission project will be approximately $830 million out of total expected costs of approximately $1.1 billion (including capitalized AFUDC).

Under a TSA between NPT and Hydro Renewable Energy, a subsidiary of HQ, NPT will sell to Hydro Renewable Energy 1,200 MW of firm electric transmission rights over the Northern Pass for a 40-year term and charge cost-based rates. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project and, during commercial operation, the ROE will be equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent. During the development and construction phases under the TSA, NPT will record non-cash AFUDC earnings. On March 18, 2011, the NHPUC filed a request with the FERC seeking rehearing on the ROE granted to Northern Pass. On August 5, 2011, FERC denied the request by the NHPUC.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE seeking permission for NPT to construct and maintain facilities that cross the U.S. border. The DOE held seven meetings in New Hampshire in mid-March 2011 seeking public comment. In response to concerns raised at these meetings, NPT revised its application to request additional time during the public comment period to allow NPT to review alternative routes. On June 15, 2011, the DOE extended the scoping comment period for at least forty-five days after NPT files an alternative route with the DOE. After the final route has been identified, certain environmental studies will need to be completed in order to obtain DOE permits. We expect to commence construction in 2014 and place the project in service in the fourth quarter of 2016.

On February 8, 2012, the New Hampshire legislature passed a bill that could potentially prohibit the use of eminent domain for the development of any non-reliability electric transmission projects such as Northern Pass. The bill is currently awaiting action by the Governor. We are reviewing the potential impact of the bill on NPT, should it be enacted, including its effect on the project's route, cost and schedule. We believe that NPT will be able to acquire the necessary rights along an acceptable route, which would make it feasible to construct the project even if the bill is enacted. Given the ultimate design needs of the project, along with siting and permit requirements, which will vary depending upon the route ultimately selected, there is a possibility for further delay in commencement of construction.

Other Transmission Transactions

On May 31, 2011, CL&P and the Connecticut Transmission Municipal Electric Energy Cooperative (CTMEEC), a non-profit municipal joint action transmission entity formed by several Connecticut municipal electric utilities, completed the sale by CL&P to CTMEEC of a segment of high voltage transmission lines built by CL&P in the town of Wallingford, Connecticut. The assets were sold at their net book value of $42.5 million, plus reimbursement of closing costs. CL&P is operating and maintaining the lines under an agreement with CTMEEC. The transaction did not include the transfer of land or equipment unrelated to electric transmission service.

Transmission Rate Base

Under our FERC-approved tariff, transmission projects generally enter rate base after they are placed in commercial operation. At the end of 2011, our transmission rate base was approximately $2.96 billion, including approximately $2.1 billion at CL&P, $390 million at PSNH and $467 million at WMECO. We forecast that our total transmission rate base will grow to approximately $4.8 billion by the end of 2016, including approximately $804 million at NPT.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The principal focus of our construction and capital improvement program is maintaining, upgrading and expanding our existing electric transmission, distribution and generation systems and our natural gas distribution system. Our consolidated capital expenditures in 2011 totaled approximately $1.2 billion, essentially all of which was expended by the Regulated companies. The 2012 capital expenditures of these companies are estimated to total approximately $1.14 billion, $500 million by CL&P, $212 million by PSNH, $251 million by WMECO, $40 million by NPT, and $94 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 we expect to become committed projects in 2012.

In 2011, CL&P s transmission capital expenditures totaled $128.6 million, and its distribution capital expenditures totaled $338.5 million. For 2012, CL&P projects transmission capital expenditures of $174 million and distribution capital expenditures of $315 million. During the period 2012 through 2016, CL&P plans to invest approximately $837 million in transmission projects, the majority of which will be for NEEWS, and $1.42 billion on distribution projects. In addition, CL&P expects to spend $11 million on regulated generation in 2012, and a total of $45 million during the period 2012 through 2016. If all of the transmission and distribution projects are built as proposed, CL&P s rate base for transmission assets is projected to increase from approximately $2.1 billion at the end of 2011 to approximately $2.45 billion by the end of 2016, and its rate base for electric distribution is projected to increase from approximately $2.6 billion to approximately $3.11 billion over the same period.

In 2011, PSNH's transmission capital expenditures totaled $68.1 million, its distribution capital expenditures totaled $98.8 million and its generation capital expenditures totaled $124.8 million. For 2012, PSNH projects transmission capital expenditures of $66 million, distribution capital expenditures of $112 million and generation capital expenditures of $34 million. During the period 2012 through 2016, PSNH plans to spend $468 million on transmission projects, $560 million on distribution projects, and $159 million on generation projects. If all of the transmission, distribution and generation projects are built as proposed, PSNH s rate base for electric transmission is projected to increase from $390 million at the end of 2011 to $721 million by the end of 2016, and its rate base for distribution and generation assets is projected to increase from approximately $1.6 billion to approximately $1.76 billion over the same period.

In 2011, WMECO's transmission capital expenditures totaled $236.8 million, its distribution capital expenditures totaled $41.8 million and solar generation expenditures were $11.7 million. In 2012, WMECO projects transmission capital expenditures of $193 million, distribution capital expenditures of $39 million and expenditures of $19 million on solar generation. During the period 2012 through 2016, WMECO plans to spend $510 million on transmission projects, with the bulk of that amount to be spent on GSRP, $199 million on distribution projects and $49 million on solar generation. If all of the transmission, distribution and generation projects are built as proposed, WMECO s rate base for electric transmission is projected to increase from $467 million at the end of 2011 to $814 million by the end of 2016 and its rate base for distribution and generation assets is projected to increase from $441 million to $498 million over the same period.

In addition, we project transmission capital expenditures by NPT of $40 million in 2012 and during the period 2012 through 2016, we project NPT to spend $812 million on Northern Pass.

In 2011, Yankee Gas capital expenditures totaled $102.8 million. For 2012, Yankee Gas projects total capital expenditures of $94 million, of which $26 million is expected to be related to basic business activities such as relocation of conflicting gas facilities and the purchase of meters, tools and information technology, $48 million related to reliability improvements, and $20 million for load growth and new business requests. During the period 2012 through 2016, Yankee Gas plans on making $564 million of capital expenditures. Future capital spending will likely be affected by price differences between the cost of natural gas and home heating oil, natural gas supply, new home construction, road reconstruction, regulatory mandates and business requirements. Excluding non-recurring major

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projects, NU expects that approximately 25 percent of Yankee Gas capital expenditures over the 2012 through 2016 period will be related to basic business activities, approximately 30 percent will be related to load growth and new business, and approximately 45 percent will be related to reliability initiatives and infrastructure. If all of Yankee Gas projects are built as proposed, Yankee Gas rate base is projected to increase from $754 million at the end of 2011 to approximately $1.04 billion by the end of 2016.

FINANCING

On April 1, 2011, CL&P completed the remarketing of $62 million of tax-exempt secured PCRBs, which mature on May 1, 2031. The PCRBs carry a coupon rate of 1.25 percent until April 1, 2012, at which time CL&P expects to remarket the bonds.

On May 26, 2011, PSNH issued $122 million of first mortgage bonds with a coupon rate of 4.05 percent and a maturity date of June 1, 2021, and used the proceeds to redeem $119.8 million of tax-exempt 1992 Series D and 1993 Series E PCRBs, each with a maturity date of May 1, 2021 and a coupon rate of 6 percent. The refinancing is expected to reduce PSNH s interest costs by approximately $2.2 million in 2012.

On September 13, 2011, PSNH issued $160 million of first mortgage bonds, due September 1, 2021, with a coupon rate of 3.20 percent, and on September 16, 2011, WMECO issued $100 million of senior unsecured notes due September 15, 2021 carrying a coupon rate of 3.50 percent.

In addition, on October 24, 2011, CL&P issued $120.5 million of PCRBs carrying a coupon rate of 4.375 percent that will mature on September 1, 2028, and $125 million of PCRBs carrying a coupon of 1.25 percent that mature on September 1, 2028 and are subject to mandatory tender on September 3, 2013. The proceeds of CL&P s issuances were used to refund $245.5 million of PCRBs that carried a coupon rate of 5.85 percent and had a maturity date of September 1, 2028. The refinancing is expected to reduce CL&P s interest costs by approximately $7.5 million in 2012.

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, PSNH, WMECO and Yankee Gas, 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.

In 2012, in addition to remarketing the $62 million PCRBs at CL&P, NU parent has a debt maturity on April 1, 2012 of $263 million, which NU expects to refinance with proceeds of a new debt issuance, and Yankee Gas has an annual sinking fund requirement of $4.3 million. Also, in 2012, we expect to issue $150 million of long-term debt comprised of $100 million by WMECO and $50 million by Yankee Gas in the second half of 2012.

NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and several other New England electric utilities are stockholders in three inactive regional nuclear generation companies, CYAPC, MYAPC and YAEC (collectively, 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.

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including 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 PURA, 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, 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 2011, PSNH s Clean Air Project, the installation of a wet flue gas desulphurization system at its Merrimack coal station to reduce its mercury and sulfur dioxide emissions, was placed into service. The Clean Air Project is expected to be fully operational in mid-2012 and is designed to capture more than 80 percent of the mercury in the coal from the coal burning stations and to reduce sulfur dioxide emissions by more than 90 percent, making Merrimack one of the cleanest coal-burning plants in the nation. We expect the final costs of the project to be approximately $422 million**.** Compliance with additional environmental laws and regulations, particularly air and water pollution control requirements, may cause changes in operations or require further investments in new equipment at existing facilities.

Water Quality Requirements

The Clean Water Act requires every point source discharger of pollutants into navigable waters to obtain a NPDES permit from the EPA 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. In each of the last three years, the costs incurred by PSNH related to compliance with NPDES and state discharge permits have not been material.

On September 29, 2011, the EPA issued for public review and comment a draft renewal NPDES permit under the Clean Water Act for PSNH s Merrimack Station. The draft permit would require PSNH to install a closed-cycle cooling system at the station. The EPA estimated that the net present value cost to install this system and operate it over a 20-year period would be approximately $112 million. On October 27, 2011, the EPA extended the initial 60-day public review and comment period on the draft permit for an additional 90 days until February 28, 2012. The EPA has no deadline to consider comments and to issue a final permit Merrimack Station can continue to operate under its current permit pending issuance of the final permit and subsequent resolution of appeals by PSNH and other parties. Due to the site specific characteristics of PSNH's other fossil fueled electric generating stations, we believe it is unlikely that they would have similar permit requirements imposed on them.

Air Quality Requirements

The Clean Air Act Amendments (CAAA), as well as New Hampshire law, impose stringent requirements on emissions of SO_2 and NO_X for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Requirements for the installation of continuous emissions monitors and expanded permitting provisions also are included.

In December 2011, the EPA finalized the Mercury and Air Toxic Standards (MATS) that require the reduction of emissions of hazardous air pollutants from new and existing coal- and oil-fired electric generating units. Commonly called the Utility MACT (maximum achievable control technology) rules, it establishes emission limits for mercury, arsenic and other hazardous air pollutants from coal- and oil-fired units. MATS is the first implementation of a nationwide emissions standard for hazardous air pollutants across all electric generating units and provides utility companies with up to five years to meet the requirements. PSNH owns and operates approximately 1,000 MW of fossil fueled electric generating units subject to MATS, including the Merrimack, Newington and Schiller stations. We believe the Clean Air Project at our Merrimack Station, together with existing equipment, will enable the facility to meet the MATS requirements. A review of the potential impact of MATS on our other PSNH units is not yet complete. Additional controls may be required at these facilities. To date, the financial impact of these potential controls has not been determined.

In New Hampshire, the Multiple Pollutant Reduction Program capped NO_X, SO_2 and CO_2 emissions beginning in 2007. In addition, a 2006 New Hampshire law required PSNH to install a wet flue gas desulphurization system to reduce mercury emissions of its coal fired plants by at least 80 percent from all PSNH coal fired stations (with the co-benefit of reductions in SO_2 emissions as well). The Clean Air Project enables PSNH to satisfy this requirement.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the RGGI, a cooperative effort by nine northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fueled electric generating plants. Because CO_2 allowances issued by any participating state are usable across all nine RGGI state programs, the individual state CO_2 trading programs, in the aggregate, 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 currently own any generating assets (other than the solar facilities owned by WMECO, which do not emit CO_2), neither is required to acquire CO_2 allowances; however, the CO_2 allowance costs borne by generators that provide energy supply to CL&P and WMECO will likely be included in wholesale rates charged to them, which costs are then recoverable from customers.

NU s carbon emission inventory accounts for and reports all direct carbon dioxide (CO_2) methane (CH_4) nitrous oxide (N_2O) sulfur hexafluoride (SF_6) emissions for operations of NU and its subsidiaries in carbon dioxide equivalents. Total carbon emissions include those from sources owned or operated by NU (Scope 1) and those that are a consequence of NU s activities, but occur from sources owned or controlled by others, such as emissions from purchased electricity and line loss during the transmission and distribution of electricity (Scope 2). NU emissions expressed in thousand metric tons of carbon dioxide equivalent (CO_2-e) for NU and its system companies for 2008 through 2010 are shown below.

	2010	**2009**	**2008**
Total CO_2-e emissions (excludes CO_2 from biomass and biofuels)	3,976	3,930	5,131

Data was collected and calculated using the World Resource Institute greenhouse gas protocol tools except for stationary combustion emissions associated with electric generating units where more accurate Continuous Emissions Monitoring System data was available. EPA reporting protocol was used for generation calculations where applicable.

PSNH anticipates that its generating units will emit between four million and five million tons of CO_2 per year excluding emissions from the operation of PSNH s Northern Wood Power Project. Under the RGGI formula, the Northern Wood Power 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 provided up to 2.5 million banked CO_2 allowances per year for PSNH s fossil fueled electric generating plants during the 2009 through 2011 compliance period. These banked CO_2 allowances initially comprised approximately one-half of the yearly CO_2 allowances required for PSNH s generating plants for compliance 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 our 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 sold to retail customers to have direct ties to renewable sources. In 2011, the total RPS obligation was 9.58 percent and it will ultimately reach 23.8 percent in 2025. Energy suppliers, like PSNH, purchase RECs from producers that generate energy from a qualifying resource and use them to satisfy the RPS requirements. PSNH also owns renewable sources and uses a portion of internally generated RECs and purchased RECs to meet 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 for each REC requirement for which PSNH is deficient. The costs of both the RECs and alternative compliance payments are recovered by PSNH through its ES rates charged to customers.

The RECs generated from PSNH s Northern Wood Power Project, a wood-burning facility, are sold to other energy suppliers and the proceeds from the sale of these RECs is credited back to customers.

Similarly, Connecticut's RPS statute requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2011, the total RPS obligation was 15 percent and will ultimately reach 27 percent in 2020. CL&P is permitted to recover any costs incurred in complying with RPS from its customers through rates.

Massachusetts RPS program also requires electricity suppliers to meet renewable energy standards. For 2011, the requirement was 15.1 percent, and will ultimately reach 27.1 percent in 2020. WMECO is permitted to recover any costs incurred in complying with RPS from its customers through rates.

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws were implemented, utility companies often disposed of residues from operations by depositing or burying them on-site or disposing of them at off-site landfills or other facilities. Typical materials disposed of include coal gasification byproducts, fuel oils, ash, and other materials that might contain polychlorinated biphenyls or that otherwise might be hazardous. 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, based upon currently available information, is 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 these practices. As of December 31, 2011, 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 $31.7 million, representing 59 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 MGP facilities. These facilities were owned and operated by our predecessor companies 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.

HWP, a wholly owned subsidiary of NU, is continuing to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal electric utility, in 1902.

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HWP is at least partially responsible for this site and has already conducted substantial investigative and remediation activities. HWP's share of the remediation costs related to this site is not recoverable from customers.

Electric and Magnetic Fields

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

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

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. The EPA 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. The EPA has mandated GHG emission reporting beginning in 2011 for emissions for certain aspects of our business including stationary combustion, volume of gas supplied to large customers and fugitive emissions of SF-6 gas and methane.

We are continually evaluating the regulatory risks and regulatory uncertainty presented by climate change concerns. 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, carbon taxes, fuel and energy taxes, or regulations requiring additional capital expenditures at our generating facilities. Product efficiency standards and regulations could impact the demand for energy use by our customers. 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.

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, (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. PSNH and its hydroelectric projects are subject to conditions set forth in such licenses, the Federal Power Act 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 that 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. PSNH is not presently encountering any of these challenges.

EMPLOYEES

As of December 31, 2011, we employed a total of 6,063 employees, excluding temporary employees, of which 1,828 were employed by CL&P, 1,243 were employed by PSNH, 346 were employed by WMECO, 413 were employed by Yankee Gas and 2,228 were employed by NUSCO. Approximately 2,279 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are members of the International Brotherhood of Electrical Workers or 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

In addition to the matters set forth under Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995 included immediately prior to Item 1, *Business,* above, we are subject to a variety of significant risks. 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 other matters. The commissions policies and regulatory actions could have a material impact on the Regulated companies financial position, results of operations and cash flows.

Our transmission, distribution and generation systems may not operate as expected, and could require unplanned expenditures, which could adversely affect our financial position, results of operations and cash flows.

Our ability to properly operate our transmission, distribution and generation systems is critical to the financial performance of our business. Our transmission, distribution and generation businesses face several operational risks, including the breakdown or failure of or damage to equipment or processes (especially due to age); labor disputes; disruptions in the delivery of electricity, including impacts on us or our customers; increased capital expenditure requirements, including those due to environmental regulation; information security risk, such as a breach of our systems on which sensitive utility customer data and account information are stored; catastrophic events such as fires, explosions, or other similar occurrences; extreme weather conditions beyond equipment and plant design capacity; and other unanticipated operations and maintenance expenses and liabilities. The failure of our transmission, distribution and generation systems to operate as planned may result in increased capital costs, reduced earnings or unplanned increases in operation and maintenance costs. At PSNH, outages at generating stations may be deemed imprudent by the NHPUC resulting in disallowance of replacement power costs. Such costs that are not recoverable from our customers would have an adverse effect on our financial position, results of operations and cash flows.

Limits on our access to and increases in the cost of 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. In addition, higher interest rates would increase our cost of borrowing, which could adversely impact our results of operations. A downgrade of our credit ratings or events beyond our control, such as a disruption in global capital and credit markets, 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 or may elect to exercise their termination rights, which would adversely affect our earnings.

We are exposed to the risk that counterparties to various arrangements who owe us money, have contracted to supply us with energy, coal, or other commodities or services, or who work with us as strategic partners, including on significant capital projects, will not be able to perform their obligations, will terminate such arrangements or, with respect to our credit facilities, fail to honor their commitments. Should any of these counterparties fail to perform their obligations or terminate such arrangements, we might be forced to replace the underlying commitment at higher market prices and/or have to delay the completion of, or cancel a capital project. Should any lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements could decrease. In any such events, our financial position, results of operations, or cash flows could be adversely affected.

Difficulties in obtaining necessary rights of way, or siting, design or other approvals for major transmission projects, environmental concerns or actions of regulatory authorities, communities or strategic partners may cause delays or cancellation of such projects, which would adversely affect our earnings.

Various factors could result in increased costs or result in delays or cancellation of our transmission projects. These include the regulatory approval process, environmental and community concerns, design and siting issues, difficulties in obtaining required rights of way and actions of strategic partners. Should any of these factors result in such delays or cancellations, our financial position, results of operations, and cash flows could be adversely affected.

Economic events or factors, changes in regulatory or legislative policy and/or regulatory decisions or construction of new generation may delay completion of or displace or result in the abandonment of our planned transmission projects or adversely affect our ability to recover our investments or result in lower than expected earnings.

Our transmission construction plans could be adversely affected by economic events or factors, new legislation, regulations, or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions. Any of such events could cause delays in, or the inability to complete or abandonment of, economic or reliability related projects, which could adversely affect our ability to achieve forecasted earnings or to recover our investments or result in lower than expected rates of return. Recoverability of all such investments in rates may be subject to prudence review at the FERC. While we believe that all of such costs have been and will be prudently incurred, we cannot predict the outcome of future reviews should they occur.

In addition, our transmission projects may be delayed or displaced by new generation facilities, which could result in reduced transmission capital investments, reduced earnings, and limited future growth prospects.

Many of our transmission projects are expected to help alleviate identified reliability issues and reduce customers' costs. However, if, due to economic events or factors or further regulatory or other delays, the in-service date for one or more of these projects is delayed, there may be increased risk of failures in the electricity transmission system and supply interruptions or blackouts, 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. Our projected earnings and growth could be adversely affected were FERC to reduce these incentives in the future below the levels presently anticipated.

Increases in electric and gas prices and/or a weak economy, can lead to changes in legislative and regulatory policy promoting energy efficiency, conservation, and self-generation and/or a reduction in our customers ability to pay their bills, which may adversely impact our business.

Energy consumption is significantly impacted by the general level of economic activity and cost of energy supply. Economic downturns or periods of high energy supply costs typically can lead to the development of legislative and regulatory policy designed to promote reductions in energy consumption and increased energy efficiency and self-generation by customers. This focus on conservation, energy efficiency and self-generation may result in a decline in electricity and gas sales in our service territories. If any such declines were to occur without corresponding adjustments in rates, then our revenues would be reduced and our future growth prospects would be limited.

In addition, 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 financial position, results of operations or cash flows.

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

The existing FERC-approved New England transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities. As new investment in regional transmission infrastructure occurs in any one state, its cost is shared across New England in accordance with a FERC approved formula found in the transmission tariff. All New England transmission owners' agreement to this regional cost allocation is set forth in the Transmission Operating Agreement. This agreement can be modified with the approval of a majority of the transmission owning utilities and approval by FERC. In addition, other parties, such as state regulators, may seek certain changes to the regional cost allocation formula, which could have adverse effects on the rates our distribution companies charge their retail customers.

FERC has issued rules requiring all regional transmission organizations and transmission owning utilities to make compliance changes to their tariffs and contracts in order to further encourage the construction of transmission for generation, including renewable generation. This compliance will require ISO-NE and New England transmission owners to develop methodologies that allow for regional planning and cost allocation for transmission projects chosen in the regional plan that are designed to meet public policy goals such as reducing greenhouse gas emissions or encouraging renewable generation. Such compliance may also allow non-incumbent utilities and other entities to participate in the planning and construction of new projects in our service area and regionally.

Changes in the Transmission Operating Agreement, the New England Transmission Tariff or legislative policy, or implementation of these new FERC planning rules, could adversely affect our transmission planning, our earnings and our prospects for growth.

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 distribution and generation businesses.

Under state law, our Regulated 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 such costs incurred by our Regulated companies, such as for construction, operation and maintenance, as well as a return on investment on their respective regulated assets, including the construction costs incurred by PSNH for the Clean Air Project at its Merrimack Station. PSNH s expenditures for the project are subject to prudence review by the NHPUC. The amount of costs incurred by the Regulated companies, coupled with increases in fuel and energy prices, could lead to consumer or regulatory resistance to the timely recovery of such costs, thereby adversely affecting our financial position, results of operations or cash flows.

Additionally, state legislators may enact laws that significantly impact our Regulated companies revenues, including by mandating electric or gas rate relief and/or by requiring surcharges to customer bills to support state programs not related to the utilities or energy policy. Such increases could pressure overall rates to our customers and our routine requests to regulators for rate relief.

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 approval to recover the costs of these contracts from the PURA 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.

PSNH meets most of its energy requirements through its own 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 energy to meet its 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.

Migration of customers from PSNH energy service to competitive energy suppliers is increasing the cost to the remaining customers of energy produced by PSNH generation assets and decrease our revenues.

PSNH s ES rates have been higher than competitive energy prices offered to some customers in recent years, due primarily to lower natural gas prices. Further increases are expected as the costs associated with the Clean Air Project are fully phased into rates. The remaining retail energy service customers are experiencing an increase in PSNH s ES rate by 5 percent to 7 percent due to migration of large commercial and industrial customers and the lower base in which to recover PSNH's fixed generation costs. This increase may in turn cause further migration and further increasing of PSNH ES rates. This trend could lead to PSNH continuing to lose retail customers and increasing the burden of supporting the cost of its generation facilities on remaining customers and being unable to support the cost of its generation facilities through an ES rate.

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

Pursuant to New Hampshire law, PSNH placed the Clean Air Project in service at its Merrimack Station in Bow, New Hampshire. PSNH s recovery of costs in constructing the project is subject to prudence review by the NHPUC. A material prudence disallowance could adversely affect PSNH s financial position, results of operations or cash flows. While we believe we have prudently incurred all expenditures to date, we cannot predict the outcome of any prudence reviews. 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 position 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, acts of war or terrorism, or cyber breaches could negatively impact our business.

Because our generation and transmission facilities are part of an interconnected regional grid, we face the risk of blackout due to a disruption on a neighboring interconnected system.

Acts of war or terrorism could target our generating, transmission and distribution facilities or our data management systems. Such actions could impair our ability to manage these facilities or operate our system effectively, resulting in loss of service to customers.

In addition, cyber intrusions targeting our information systems could impair our ability to properly manage our data, networks, systems and programs, adversely affect our business operations or lead to release of confidential customer information or critical operating information. While we have implemented measures designed to prevent cyber-attacks and mitigate their effects should they occur, our systems are vulnerable to unauthorized access and cyber intrusions. We cannot discount the possibility that a security breach may occur or quantify the potential impact of such an event.

Any such grid disturbances, acts of war or terrorism, or cyber breaches could result in a significant decrease in revenues, significant expense to repair system damage or security breaches, and liability claims, which could have a material adverse impact on our financial position, results of operations or cash flows.

Severe storms could cause significant damage to our electrical facilities requiring extensive capital expenditures, the recovery for which is subject to approval by regulators.

Severe weather, such as Tropical Storm Irene in August 2011 and the October 29, 2011 snowstorm, and other such major natural disasters, could cause widespread damage to our transmission and distribution facilities. The resulting cost of repairing damage to our facilities and the potential disruption of our operations could exceed our financial reserves and insurance.

Tropical Storm Irene and the October 2011 snowstorm caused significant damage to our transmission and distribution systems. As a result, we have recorded $312 million (predominantly at CL&P) for estimated restoration costs as regulatory assets, subject to future recovery from customers. If, upon review, any of our state regulatory authorities finds that our actions were imprudent, some of those restoration costs may not be recoverable from customers. The inability to recover a significant amount of such costs could have an adverse effect on our financial position, results of operations and cash flows.

Market performance or changes in assumptions 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. Our future pension obligations, costs and liabilities are highly dependent on a variety of factors beyond our control. These factors include estimated investment returns, interest rates, discount rates, health care cost trends, benefit changes, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs could increase significantly. In 2008 and 2009, due to the financial crisis, the value of our pension assets declined. As a result, we made a contribution of approximately $144 million in 2011 and expect to make an approximate $197 million contribution in 2012. In addition, various factors, including underperformance of plan investments and changes in law or regulation, could increase the amount of contributions required to fund our pension plan in the future. Additional 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 negatively affect our financial position, results of operations or cash flows.

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 that 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 financial position, results of operations or 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 financial position, results of operations or 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*, included in this Annual Report on Form 10-K.

As a holding company with no revenue-generating operations, NU parent s liquidity 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 debt service obligations and to pay dividends on its common shares is largely dependent on the ability of its subsidiaries to pay dividends to or to repay borrowings from 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 operating expenses, 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 to 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, dividends and its own debt obligations would be restricted.

Risks Related to the Pending Merger with NSTAR

We may be unable to obtain the approvals required to complete the merger or such approvals may contain material restrictions or conditions which may make it undesirable to complete the merger.

The merger is subject to numerous conditions, including the approval of PURA and the DPU, which may not approve the merger, or such approvals may impose conditions on the completion, or require changes to the terms of the merger, including restrictions on the business, operations or financial performance of the combined company, which could be adverse to the company's interests. These conditions or changes could also delay or increase the cost of the merger or limit the net income or financial prospects of the combined company.

We will be subject to business uncertainties and contractual restrictions while the merger is pending.

The work required to complete the merger may place a significant burden on management and internal resources. Management's attention and other company resources may be focused on the merger instead of on day-to-day management activities, including pursuing other opportunities beneficial to NU. In addition, while the merger is pending our business operations are restricted by the merger agreement to ordinary course of business activities consistent with past practice, which may cause us to forgo otherwise beneficial business opportunities.

We may lose management personnel and other key employees and be unable to attract and retain such personnel and employees.

Uncertainties about the effect of the merger on management personnel and employees may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, which could affect our financial performance.

The merger may not be completed, which may have an adverse effect on our share price and future business and financial results, and we could face litigation concerning the merger, whether or not the merger is consummated.

Failure to complete the merger could negatively affect our share price, as well as our future business and financial results. If the merger is not completed for certain reasons specified in the merger agreement, we may be required to pay NSTAR a termination fee of $135 million plus up to $35 million of certain expenses incurred by NSTAR. In addition, we must pay our own costs related to the merger including, among others, legal, accounting, advisory, financing and filing fees and printing costs, whether the merger is completed or not. Further, whether or not the merger is completed, we could be subject to litigation related to the failure to complete the merger or other factors, which may adversely affect our business, financial results and share price.

If completed, the merger may not achieve its intended results.

We entered into the merger agreement with the expectation that the merger would result in various benefits. If the merger is completed, our ability to achieve the anticipated benefits will be subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could adversely affect our business, financial results and share price.

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, 2011, our electric operating subsidiaries owned 32 transmission and 404 distribution substations that had an aggregate transformer capacity of 6,584,000 kilovolt amperes (kVa) and 26,839,000 kVa, respectively; 2,969 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; 34,972 pole miles of overhead and 4,000 conduit bank miles of underground distribution lines; and 551,338 underground and overhead line transformers in service with an aggregate capacity of 38,721,890 kVa.

Electric Generating Plants

As of December 31, 2011, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (kilowatts)
Total - Fossil-Steam Plants	5 units	1952-74	953,805
Total - Hydro	20 units	1901-83	68,994
Total - Internal Combustion	5 units	1968-70	101,869
Total - Biomass - Steam Plant	1 unit	1954-2006	42,594
Total PSNH Generating Plant	31 units		1,167,262

*

Claimed capability represents winter ratings as of December 31, 2011. The combined nameplate capacity of the generating plants is approximately 1,200 MW.

As of December 31, 2011, WMECO owned the following electric generating plant:

Type of Plant	Number of Sites	Year Installed	Claimed Capability** (kilowatts)
Total - Solar Fixed Tilt, Photovoltaic	2 sites	2010-11	4,100

** Claimed capability represents the direct current nameplate capacity of the plant.

CL&P did not own any electric generating plants during 2011.

Yankee Gas

As of December 31, 2011, Yankee Gas owned 28 active gate stations, 200 district regulator stations, and 3,256 miles of natural gas main pipeline. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, and 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 PURA determines that such facilities will be more cost effective than other options for mitigating FMCC and Locational Installed Capacity (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 PURA and a determination by the PURA that such purchase is in the public interest. Finally, Section 127 of Public Act 11-80 allows CL&P to submit a proposal to the DEEP to build, own or operate one or more generation facilities up to 10 MWs using Class 1 renewable energy.

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. PSNH s status as a public utility gives it the ability to petition the NHPUC for the right to exercise eminent domain for its transmission and distribution services in appropriate circumstances.

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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 holds valid franchises to sell gas in the areas in which Yankee Gas supplies gas service, which it acquired either directly or from its predecessors in interest. 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 PURA 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.

<u>Yankee Companies v. U.S. Department of Energy</u>

The Yankee Companies (YAEC, MYAPC, and CYAPC) commenced litigation in 1998 against the 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. On September 7, 2010, the trial court issued its decision following remand and awarded CYAPC $39.7 million, YAEC $21.2 million and MYAPC $81.7 million. The DOE filed an appeal and the Yankee Companies cross-appealed. Briefs were filed and oral arguments in the appeal of the remanded case occurred on November 7, 2011. If the Court follows its previous schedule, a decision could be handed down within six months of the argument (second quarter 2012). The application of any damages that 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. On November 18, 2011, the court ordered the record closed in the YAEC case, and closed the record in the CYAPC and MYAPC cases subject to a limited opportunity of the government to reopen the records for further limited proceedings. The parties post-trial briefs will be filed during the first quarter of 2012 with a decision to come thereafter.

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 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 activity and expenditures at the sites are ongoing. 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. Judgment was entered on March 31, 2010. On April 23, 2010, the NU Companies filed a Notice of Appeal with respect to the court s decision, which has been fully briefed. The Phase II trial, which would determine what portion of the remediation costs at the Waterbury-North site are attributable to UGI's control, was held in August and September, 2011. We expect a decision in the first quarter of 2012. Any recovery resulting from the case (following the appeal and the Waterbury-North complaint) 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.

Bankruptcy of Independent Power Producer

On February 1, 2011, an independent power producer, AES Thames, L.L.C. (Thames), which is the counterparty to a CL&P electricity purchase agreement, filed a voluntary Chapter 11 petition in the U.S. Bankruptcy Court in Delaware (Case No. 11-10334). Thames owned and operated a 181 MW coal fired generation plant in Montville, Connecticut providing electric energy to CL&P and process steam to a nearby paperboard manufacturer. Citing market conditions and regulatory and legislative uncertainties, Thames advised CL&P on January 24, 2011 that it was shutting the plant down for an undetermined period. Under an amendment to the electricity purchase agreement entered into in 1999, Thames had agreed to supply CL&P with energy from the plant for a reduced price in exchange for a substantial prepayment. The electricity purchase agreement was due to expire in 2015. On January 23, 2012, the bankruptcy case was converted to a liquidation under Chapter 7 of the bankruptcy code. A trustee has been appointed. No further deliveries under the CL&P contract with Thames will be made. This matter is not expected to have any impact on CL&P s results of operations.

4.

Conservation Law Foundation v. PSNH

On July 21, 2011, the Conservation Law Foundation (CLF) filed a citizens suit under the provisions of the federal Clean Air Act against PSNH alleging permitting violations at the company s Merrimack generating station. The suit alleges that PSNH failed to have proper permits for replacement of the Unit 2 turbine at Merrimack and installation of activated carbon injection equipment for the unit, and violated a permit condition concerning operation of the electrostatic precipitators at the station. The suit seeks injunctive relief, civil penalties, and costs. CLF has pursued similar claims before the NHPUC, the Air Resources Council, and the Site Evaluation Committee, all of which have been denied. PSNH believes this suit is without merit and intends to defend it vigorously.

5.

Other Legal Proceedings

For further discussion of legal proceedings, see Item 1, *Business:* - Regulated Electric Distribution, -Regulated Gas Distribution - Yankee Gas Services Company, and - 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 15, 2012. 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	42	Vice President - Accounting and Controller.
Gregory B. Butler	54	Senior Vice President and General Counsel.
Jean M. LaVecchia*	60	Vice President - Human Resources of NUSCO.
David R. McHale	51	Executive Vice President and Chief Financial Officer.
Leon J. Olivier	63	Executive Vice President and Chief Operating Officer.
James B. Robb*	51	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	66	Chairman of the Board, President and Chief Executive Officer.

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

Jay S. Buth. Mr. Buth was elected 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 was elected 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, PSNH and WMECO, 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, PSNH and WMECO 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, Inc. 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.

Mine Safety Disclosures

Not applicable.

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 sales prices for the past two years, by quarter, are shown below:

Year	**Quarter**	**High**	**Low**
2011	First	$ 35.13	$ 31.19
	Second	36.47	33.31
	Third	35.87	30.02
	Fourth	36.40	30.80
2010	First	$ 28.00	$ 24.68
	Second	28.21	24.83
	Third	30.25	25.24
	Fourth	32.21	29.51

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, 2011.

As of January 31, 2011, there were 38,300 registered common shareholders of our company on record. As of the same date, there were a total of 196,069,808 common shares issued.

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 14, 2012, our Board of Trustees declared a dividend of 29.375 cents per share, payable on March 30, 2012 to shareholders of record as of March 1, 2012.

On October 11, 2011, our Board of Trustees declared a dividend of 27.5 cents per share, payable on December 30, 2011 to shareholders of record as of November 10, 2011.

On July 12, 2011, our Board of Trustees declared a dividend of 27.5 cents per share, payable on September 30, 2011 to shareholders of record as of September 1, 2011.

On April 12, 2011, our Board of Trustees declared a dividend of 27.5 cents per share, payable on June 30, 2011 to shareholders of record as of June 1, 2011.

On February 8, 2011, our Board of Trustees declared a dividend of 27.5 cents per share, payable on March 31, 2011 to shareholders of record as of March 1, 2011.

On October 12, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on December 31, 2010 to shareholders of record as of December 1, 2010.

On July 12, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on September 30, 2010 to shareholders of record as of September 1, 2010.

On April 13, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on June 30, 2010 to shareholders of record as of June 1, 2010.

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.

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 Item 8, *Financial Statements and Supplementary Data*, 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 2011 and 2010, CL&P approved and paid $243.2 million and $217.7 million, respectively, of common stock dividends to NU.

During 2011 and 2010, PSNH approved and paid $58.8 million and $50.6 million, respectively, of common stock dividends to NU.

During 2011 and 2010, WMECO approved and paid $26.3 million and $14.9 million, respectively, of common stock dividends to NU.

For information regarding securities authorized for issuance under equity compensation plans, see Item 12, *Security Ownership of Certain Beneficial Owners and Management and Related 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 common share information)	2011	2010	2009	2008	2007
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 10,403,065	$ 9,567,726	$ 8,839,965	$ 8,207,876	$ 7,229,945
Total Assets (f)	15,647,066	14,472,601	14,057,679	13,988,480	11,581,822
Total Capitalization (a)	9,078,321	8,627,985	8,253,323	7,293,960	6,667,920
Obligations Under Capital Leases (a)	12,358	12,236	12,873	13,397	14,743
Income Statement Data:					
Operating Revenues	$ 4,465,657	$ 4,898,167	$ 5,439,430	$ 5,800,095	$ 5,822,226
Income from Continuing Operations	400,513	394,107	335,592	266,387	251,455
Income from Discontinued Operations	-	-	-	-	587
Net Income Attributable to Noncontrolling Interests	5,820	6,158	5,559	5,559	5,559
Net Income Attributable to Controlling Interests	$ 394,693	$ 387,949	$ 330,033	$ 260,828	$ 246,483

Common Share Data:					
Basic Earnings Per Common Share:					
Income from Continuing Operations	$ 2.22	$ 2.20	$ 1.91	$ 1.68	$ 1.59
Income from Discontinued Operations	-	-	-	-	-
Net Income Attributable to Controlling Interests	$ 2.22	$ 2.20	$ 1.91	$ 1.68	$ 1.59
Diluted Earnings Per Common Share:					
Income from Continuing Operations	$ 2.22	$ 2.19	$ 1.91	$ 1.67	$ 1.59
Income from Discontinued Operations	-	-	-	-	-
Net Income Attributable to Controlling Interests	$ 2.22	$ 2.19	$ 1.91	$ 1.67	$ 1.59
Weighted Average Common Shares Outstanding					
Basic	177,410,167	176,636,086	172,567,928	155,531,846	154,759,727
Diluted	177,804,568	176,885,387	172,717,246	155,999,240	155,304,361
Dividends Declared Per Share	$ 1.10	$ 1.03	$ 0.95	$ 0.83	$ 0.78
Market Price - Closing (high) (b)	$ 36.31	$ 32.05	$ 26.33	$ 31.15	$ 33.53
Market Price - Closing (low) (b)	$ 30.46	$ 24.78	$ 19.45	$ 19.15	$ 26.93
Market Price - Closing (end of year) (b)	$ 36.07	$ 31.88	$ 25.79	$ 24.06	$ 31.31
Book Value Per Share (end of year)	$ 22.65	$ 21.60	$ 20.37	$ 19.38	$ 18.79
Tangible Book Value Per Share (end of year) (c)	$ 21.03	$ 19.97	$ 18.74	$ 17.54	$ 16.93
	10.1	10.7	10.2	8.8	8.6

Rate of Return Earned on Average Common Equity (%) (d)					
Market-to-Book Ratio (end of year) (e)	1.6	1.5	1.3	1.2	1.7
Capitalization:					
Total Equity	44 %	44 %	44 %	41 %	44 %
Preferred Stock, not subject to mandatory redemption	1	1	1	2	2
Long-Term Debt (a)	55	55	55	57	54
	100 %	100 %	100 %	100 %	100 %

(a) Includes portions due within one year, but excludes RRBs for Long-Term Debt.
(b) Market price information reflects closing prices as reflected by the New York Stock Exchange.
(c) Common Shareholders' Equity adjusted for goodwill and intangibles divided by total common shares outstanding.
(d) Net Income divided by average Common Shareholders' Equity.
(e) The closing market price divided by the book value per share.
(f) As of December 31, 2011, Total Assets has been adjusted to reflect the current portions of regulatory assets and liabilities, and related deferred tax amounts, as current assets and liabilities. Amounts as of December 31, 2010 have been reclassified to conform to the December 31, 2011 presentation.

CL&P Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2011	2010	2009	2008	2007
Operating Revenues	$ 2,548,387	$ 2,999,102	$ 3,424,538	$ 3,558,361	$ 3,681,817
Net Income	250,164	244,143	216,316	191,158	133,564
Cash Dividends on Common Stock	243,218	217,691	113,848	106,461	79,181
Property, Plant and Equipment, Net	5,827,384	5,586,504	5,340,561	5,089,124	4,401,846
Total Assets (b)	8,791,396	8,255,192	8,364,564	8,336,118	7,018,099
Rate Reduction Bonds	-	-	195,587	378,195	548,686
Long-Term Debt (a)	2,583,753	2,583,102	2,582,361	2,270,414	2,028,546
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	10,715	10,613	10,956	11,207	13,602

PSNH Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2011	2010	2009	2008	2007
Operating Revenues	$ 1,013,003	$ 1,033,439	$ 1,109,591	$ 1,141,202	$ 1,083,072
Net Income	100,267	90,067	65,570	58,067	54,434
Cash Dividends on Common Stock	58,828	50,584	40,844	36,376	30,720
Property, Plant and Equipment, Net	2,256,688	2,053,281	1,814,714	1,580,985	1,388,405
Total Assets (b)	3,116,541	2,879,121	2,697,191	2,628,833	2,106,969
Rate Reduction Bonds	85,368	138,247	188,113	235,139	282,018
Long-Term Debt (a)	997,722	836,365	836,255	686,779	576,997
Obligations Under Capital Leases (a)	1,326	1,428	1,670	1,931	1,141

WMECO Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2011	2010	2009	2008	2007
Operating Revenues	$ 417,315	$ 395,161	$ 402,413	$ 441,527	$ 464,745
Net Income	43,054	23,090	26,196	18,330	23,604
Cash Dividends on Common Stock	26,305	14,882	18,203	39,706	12,779
Property, Plant and Equipment, Net	1,077,833	817,146	705,760	624,205	559,357
Total Assets	1,502,893	1,199,559	1,101,800	1,048,489	991,088
Rate Reduction Bonds	26,892	43,325	58,735	73,176	86,731
Long-Term Debt (a)	499,545	400,288	305,475	303,868	303,872
Obligations Under Capital Leases (a)	141	83	105	126	-

(a) Includes portions due within one year, but excludes RRBs for Long-Term Debt.

(b) As of December 31, 2011, Total Assets has been adjusted to reflect the current portions of regulatory assets and liabilities, and related deferred tax amounts, as current assets and liabilities. Amounts as of December 31, 2010 have been reclassified to conform to the December 31, 2011 presentation.

See the *Combined Notes to Consolidated Financial Statements* in this Annual Report on Form 10-K for a description of any accounting changes materially affecting the comparability of the information reflected in the tables above.

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 diluted basis.

Refer to the Glossary of Terms included in this Annual Report on Form 10-K for abbreviations and acronyms used throughout this *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

The only common equity securities that are publicly traded are common shares of NU. The earnings and 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 GAAP that is calculated by dividing the Net Income Attributable to Controlling Interests of each business by the weighted average 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 diluted EPS determined in accordance with GAAP as an indicator of operating performance.

The discussion below also includes non-GAAP financial measures referencing our 2011 earnings and EPS excluding expenses related to NU's pending merger with NSTAR and a non-recurring charge at CL&P for the establishment of a reserve to provide bill credits to its residential customers and donations to charitable organizations, as well as our 2010 earnings and EPS excluding merger expenses incurred in 2010 and certain non-recurring benefits from the settlement of tax issues. We use these non-GAAP financial measures to more fully compare and explain the 2011, 2010 and 2009 results without including the impact of these non-recurring items. Due to the nature and significance of these items on Net Income Attributable to Controlling Interests, 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 Interests 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 diluted EPS and Net Income Attributable to Controlling Interests 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. All forward-looking information for 2012 and thereafter provided in this *Management s Discussion and Analysis* assumes we will operate on a stand-alone basis, excluding the impacts of the pending merger with NSTAR, unless otherwise indicated.

Financial Condition and Business Analysis

Pending Merger with NSTAR:

On October 18, 2010, NU and NSTAR announced that each company's Board of Trustees unanimously approved a merger agreement (the agreement), under which NSTAR will become a direct wholly owned subsidiary of NU. On October 14, 2011, NU and NSTAR extended the termination date of the agreement, as defined therein, from October 16, 2011 to April 16, 2012. The transaction is structured as a merger of equals in a tax-free exchange of shares. Under the terms of the agreement, NSTAR shareholders will receive 1.312 NU common shares for each NSTAR common share that they own (the exchange ratio). Following the merger, NU will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire. On March 4, 2011, NU shareholders approved the agreement, approved an increase in the number of NU common shares authorized for issuance by 155 million common shares to 380 million common shares and fixed the number of trustees at 14. NSTAR shareholders approved the agreement on March 4, 2011.

Subject to the conditions in the agreement, our first quarterly dividend per common share paid after the closing of the merger will be increased to an amount that is at least equal, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing.

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. NU and NSTAR are awaiting approvals from PURA and the DPU. PURA is scheduled to issue a final decision on April 2, 2012. On February 15, 2012, NU and NSTAR reached comprehensive merger-related settlement agreements with both the Massachusetts Attorney General and the Massachusetts Department of Energy Resources agreeing to certain conditions with respect to the merger, which are subject to DPU approval and have been requested by the parties to be approved on April 4, 2012. If both PURA and the DPU issue acceptable decisions by such dates, we expect the merger will be consummated by April 16, 2012. For further information regarding regulatory approvals on the pending merger, see Regulatory Developments and Rate Matters Regulatory Approvals for Pending Merger with NSTAR, in this *Management's Discussion and Analysis.*

Executive Summary

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

Results:

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We earned $394.7 million, or $2.22 per share, in 2011, compared with $387.9 million, or $2.19 per share, in 2010. Excluding merger-related costs of $11.3 million, or $0.06 per share, and a non-recurring charge at CL&P of $17.9 million, or $0.10 per share, we earned $423.9 million, or $2.38 per share, in 2011. The non-recurring charge at CL&P relates to the establishment of a reserve to provide bill credits to its residential customers and donations to charitable organizations (storm fund reserve). Improved results in 2011 were due primarily to the impact of electric distribution rate case decisions that were effective July 1, 2010 for CL&P and PSNH and February 1, 2011 for WMECO and the impact of a higher level of investment in transmission infrastructure.

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Our Regulated companies earned $420.4 million, or $2.36 per share, in 2011, including the $17.9 million CL&P storm fund reserve, compared with $384 million, or $2.16 per share, in 2010.

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The distribution segment of our Regulated companies earned $220.8 million, or $1.24 per share, in 2011, including the $17.9 million CL&P storm fund reserve, compared with $206.2 million, or $1.16 per share, in 2010. The transmission segment of our Regulated companies earned $199.6 million, or $1.12 per share, in 2011, compared with $177.8 million, or $1.00 per share, in 2010.

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NU parent and other companies recorded net expenses of $25.7 million, or $0.14 per share, in 2011, compared with earnings of $3.9 million, or $0.03 per share, in 2010. In 2011, excluding merger-related costs of $11.3 million, or $0.06 per share, NU parent and other companies recorded net expenses of $14.4 million, or $0.08 per share. In 2010, results included a non-recurring benefit of $15.7 million, or $0.09 per share, associated with the settlement of tax issues and a charge of $9.4 million, or $0.06 per share, associated with merger-related costs.

2011 Major Storm Items:

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On August 28, 2011, Tropical Storm Irene caused extensive damage to our distribution system resulting in incremental restoration costs of $135.6 million, $123.8 million of which were incurred by CL&P. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages. CL&P capitalized $18.2 million of the restoration costs and deferred $105.6 million for future recovery.

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On October 29, 2011, an unprecedented storm inundated our service territory with heavy snow causing significant damage to our distribution and transmission systems resulting in incremental restoration costs of $218.5 million, $22.6 million of which were capitalized and $195.9 million were deferred for future recovery. Approximately 1.2 million of our electric distribution customers were without power at the peak of the outages. This was the largest storm in CL&P s and WMECO's history and third largest in PSNH s history in terms of customer outages. CL&P s portion of incremental restoration costs was $174.6 million, of which $16.9 million was capitalized and $157.7 million was deferred for future recovery.

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The storms met the regulatory criteria for cost deferral and as a result, except for the CL&P storm fund reserve, they had no material impact on our results of operations. We believe our response to the storm damage was prudent and therefore we believe it is probable that CL&P, PSNH and WMECO will be allowed to recover these storm costs. Each operating company will seek recovery of its estimated deferred storm costs through its applicable regulatory recovery process.

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CL&P recorded a storm fund reserve of $30 million ($17.9 million after-tax) to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011 as a result of the October snowstorm, and to provide donations to certain Connecticut charitable organizations. CL&P will not seek to recover this amount in its rates.

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A number of governmental inquiries have been initiated in Connecticut, New Hampshire and Massachusetts to review the response of utilities and other entities to Tropical Storm Irene and the October snowstorm. Certain reviews were completed while other inquiries are expected to be completed in the second quarter of 2012.

Strategy, Legislative, Regulatory and Other Items:

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On June 29, 2011, the DPUC (now PURA) issued a final decision in the Yankee Gas rate proceeding that was amended on September 28, 2011. The decision resulted in essentially no changes to distribution rates for 2011 and an increase of approximately $7 million in Yankee Gas annual revenues beginning July 1, 2012.

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On September 30, 2011, several parties filed a joint complaint with the FERC alleging that the base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by New England transmission owners, including CL&P, PSNH and WMECO, is unjust and unreasonable, and seeking an order to reduce the rate from 11.14 percent to 9.2 percent. On October 20, 2011, the New England transmission owners filed their response seeking dismissal of the complaint on the basis that the complainants failed to demonstrate that the existing base ROE is unjust and unreasonable and provided testimony and analysis demonstrating that the 11.14 percent base ROE remains just and reasonable. The FERC has not yet issued an order in this proceeding.

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On September 13, 2011, CL&P and WMECO received the required permit from U.S. Army Corps of Engineers allowing them to commence full construction of GSRP. The $718 million project is expected to be placed in service in late 2013. As of December 31, 2011, GSRP was approximately 50 percent complete.

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In September 2011, the Clean Air Project was placed in service at PSNH s Merrimack Station. By November 2011, both of the Merrimack Station s coal-fired units were integrated with the scrubber, which is reducing emissions from the units. Finalization of project activities, including water discharge enhancements, is expected in mid-2012. We expect the project will cost approximately $422 million.

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Yankee Gas WWL project was completed and placed in service in November 2011. Project costs totaled approximately $54 million, $3.6 million below the previous estimate of $57.6 million.

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On December 23, 2011, CL&P filed a siting application with the Connecticut Siting Council to build the 40-mile, $218 million Connecticut section of the IRP. In early 2012, National Grid is expected to file siting applications with regulators in Massachusetts and Rhode Island to build its sections of the IRP. We expect to receive approvals from all three states in late 2013 and to place the IRP in service by late 2015.

Liquidity:

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Cash and cash equivalents totaled $6.6 million as of December 31, 2011, compared with $23.4 million as of December 31, 2010, while cash capital expenditures totaled $1.1 billion in 2011, compared with $954.5 million in 2010.

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On February 14, 2012, our Board of Trustees declared a quarterly common dividend of $0.29375 per share, payable on March 30, 2012 to shareholders of record as of March 1, 2012, which equates to $1.175 per share on an annualized basis. Assuming our pending merger with NSTAR closes in 2012 after NSTAR pays its March 30, 2012 dividend of $0.45 per share, the terms of the merger agreement would require NU's first quarterly dividend paid after the merger to be at least $0.343 per share, or at least $1.372 per share on an annualized basis.

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Cash flows provided by operating activities in 2011 totaled $901.1 million, compared with $832.6 million in 2010 (amounts are net of RRB payments). The improved cash flows in 2011 were due primarily to the impact of the recent electric distribution rate case decisions and 2011 income tax refunds, as compared to 2010 income tax payments, partially offset by a Pension Plan contribution and cash disbursements associated with major storm costs. On a stand-alone basis, 2012 cash flows provided by operating activities, net of RRB payments, are expected to be lower than in 2011 due primarily to approximately $50 million more in Pension Plan contributions than in 2011 and approximately $27 million in bill credits provided to CL&P residential customers in February 2012.

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In 2011, we issued $260 million of new long-term debt consisting of $160 million by PSNH and $100 million by WMECO. Additionally, CL&P remarketed $62 million of tax-exempt secured PCRBs in April 2011 and refinanced $245.5 million of PCRBs in October 2011. PSNH refinanced $119.8 million of PCRBs in May 2011. In April 2012, NU parent has a debt maturity of $263 million, which we expect will be refinanced. In addition to remarketing the CL&P $62 million PCRBs, we expect to issue $150 million of long-term debt comprised of $100 million by WMECO and $50 million by Yankee Gas in the second half of 2012.

<u>Overview</u>

Consolidated: 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 Interests and diluted EPS, for 2011, 2010 and 2009 is as follows:

	For the Years Ended December 31,					
	2011		2010		2009	
(Millions of Dollars, except per share amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income Attributable to Controlling Interests (GAAP)	$ 394.7	$ 2.22	$ 387.9	$ 2.19	$ 330.0	$ 1.91

Regulated Companies	$	438.3	$	2.46	$	384.0	$	2.16	$	323.5	$	1.87
NU Parent and Other Companies		(14.4)		(0.08)		(2.4)		(0.00)		6.5		0.04
Non-GAAP Earnings		423.9		2.38		381.6		2.16		330.0		1.91
Non-Recurring Tax Settlements		-		-		15.7		0.09		-		-
Merger-Related Costs		(11.3)		(0.06)		(9.4)		(0.06)		-		-
Storm Fund Reserve		(17.9)		(0.10)		-		-		-		-
Net Income Attributable to Controlling Interests (GAAP)	$	394.7	$	2.22	$	387.9	$	2.19	$	330.0	$	1.91

Improved results in 2011 were due primarily to the impact of electric distribution rate case decisions that were effective July 1, 2010 for CL&P and PSNH and February 1, 2011 for WMECO, the impact of a higher level of investment in transmission infrastructure, colder than normal weather in the first quarter of 2011, continued cost management efforts, and the absence of a net charge of approximately $3 million, or approximately $0.02 per share, taken in the first quarter of 2010 associated with the enactment of the 2010 Healthcare

Act. These benefits were partially offset by a decline in NU parent and other companies' results, a second quarter 2011 refund to transmission wholesale customers, as compared to a recovery from those customers in 2010, lower retail electric sales in 2011, compared to 2010, as well as higher Pension and PBOP costs, depreciation, property taxes and the storm fund reserve.

Regulated Companies: Our Regulated companies consist of the electric distribution and transmission segments, with the Yankee Gas natural gas distribution segment and PSNH and WMECO generation activities included in the distribution segment. A summary of our Regulated companies' earnings by segment for 2011, 2010 and 2009 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars)	**2011**		**2010**		**2009**	
CL&P Transmission	$	151.9	$	143.9	$	136.8
PSNH Transmission		24.1		20.7		18.0
WMECO Transmission		22.8		13.0		9.5
NPT		0.8		0.2		-
Total Transmission		199.6		177.8		164.3
CL&P Distribution		110.6		94.1		74.0
PSNH Distribution		76.2		69.3		47.5
WMECO Distribution		20.2		10.1		16.7
Yankee Gas		31.7		32.7		21.0
Total Distribution		238.7		206.2		159.2
Subtotal - Regulated Companies Earnings Before Non-Recurring Charge	$	438.3	$	384.0	$	323.5
Storm Fund Reserve [1]	$	(17.9)	$	-	$	-
Net Income - Regulated Companies	$	420.4	$	384.0	$	323.5

(1)

Attributable to the CL&P distribution segment.

The increased 2011 transmission segment earnings as compared to 2010 were due primarily to a higher level of investment in transmission infrastructure, and a higher proportion of equity funding to support the transmission investments, partially offset by a 2011 refund to transmission wholesale customers, as compared to a recovery from those customers in 2010, primarily impacting CL&P. The increased 2010 transmission segment earnings as compared to 2009 reflect a higher level of investment in transmission infrastructure. Our transmission rate base totaled $2.96 billion at the end of 2011, compared with $2.76 billion at the end of 2010.

CL&P s 2011 distribution segment earnings, excluding the $17.9 million storm fund reserve, were $16.5 million higher than 2010 due primarily to the impact of the 2010 distribution rate case decision that was effective July 1, 2010 and included an incremental rate increase effective July 1, 2011, lower uncollectibles expense and lower income taxes.

Partially offsetting these favorable items were higher Pension and PBOP costs, a 1.5 percent decrease in retail electric sales and higher depreciation and property taxes. CL&P s distribution segment regulatory ROE was 9.4 percent in 2011, as compared to 7.9 percent in 2010.

PSNH s 2011 distribution segment earnings were $6.9 million higher than 2010 due primarily to higher revenues as a result of the permanent distribution rate increase effective July 1, 2010, and higher generation-related earnings, partially offset by the absence of the 2010 favorable impact of the distribution rate case settlement, which allowed for the recovery of certain actual expenses retroactive to August 1, 2009, higher property taxes and a 0.4 percent decrease in retail electric sales. PSNH s distribution segment regulatory ROE was 9.7 percent in 2011, as compared to 10.2 percent in 2010.

WMECO s 2011 distribution segment earnings were $10.1 million higher than 2010 due primarily to the impact of the distribution rate case decision effective February 1, 2011 and lower operations and maintenance costs, partially offset by a $5.3 million pre-tax charge to establish a reserve related to a wholesale billing adjustment, and higher depreciation and amortization. WMECO s distribution segment regulatory ROE was 9 percent in 2011, as compared to 4.6 percent in 2010.

Yankee Gas 2011 earnings were $1 million lower than 2010 due primarily to higher pension and PBOP costs, the absence of a 2010 benefit related to the settlement of various tax matters, and higher depreciation and property taxes. These unfavorable impacts were partially offset by higher revenues resulting from an 8 percent increase in total firm natural gas sales, and lower uncollectibles expense. Yankee Gas regulatory ROE was 9.3 percent in 2011, as compared to 8.6 percent in 2010.

On August 28, 2011, Tropical Storm Irene caused extensive damage to our distribution system resulting in incremental restoration costs of $135.6 million. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages.

On October 29, 2011, an unprecedented storm inundated our service territory with heavy snow causing significant damage to our distribution and transmission systems resulting in incremental restoration costs of $218.5 million. Approximately 1.2 million of our electric distribution customers were without power at the peak of the outages, with 810,000 of those customers in Connecticut, 237,000 in New Hampshire, and 140,000 in Massachusetts. In terms of customer outages, this was the most severe storm in CL&P s history, surpassing Tropical Storm Irene; the third most severe in PSNH s history, following a December 2008 ice storm and a February 2010 winter storm; and the most severe in WMECO's history.

Estimated incremental restoration costs related to the storms are summarized in the table below and consist of costs that are deferred for future recovery and costs that are capitalized:

	For the Year Ended December 31, 2011		
(Millions of Dollars)	**Deferred for Future Recovery**	**Capitalized**	**Total Incremental Costs**
Tropical Storm Irene:			
CL&P	$ 105.6	$ 18.2	$ 123.8
PSNH	7.0	1.1	8.1
WMECO	3.2	0.5	3.7
Total Tropical Storm Irene	115.8	19.8	135.6
October Snowstorm:			
CL&P	157.7	16.9	174.6
PSNH	14.7	2.2	16.9
WMECO	23.5	3.5	27.0
Total October Snowstorm	195.9	22.6	218.5
Total Storm Costs	$ 311.7	$ 42.4	$ 354.1

The storms met the regulatory criteria for cost deferral in Connecticut, New Hampshire and Massachusetts and as a result, except for the CL&P storm fund reserve, the storm costs had no material impact on the results of operations of CL&P, PSNH or WMECO. We believe our response to the storm damage was prudent and therefore we believe it is probable that CL&P, PSNH and WMECO will be allowed to recover these costs. Each operating company will seek recovery of its costs through its applicable regulatory recovery process. For further information regarding various reviews on storm response and preparedness, see Regulatory Developments and Rate Matters - 2011 Major Storms, in this *Management's Discussion and Analysis.*

CL&P recorded a pre-tax charge for a storm fund reserve of $30 million, in the fourth quarter of 2011, to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011 as a result of the October snowstorm, and to provide contributions to certain Connecticut charitable organizations. Approximately $27 million of the storm fund reserve was used to provide a one-time credit on the February 2012 bills of approximately 192,000 CL&P customers and approximately $3 million was paid to charitable organizations in December 2011. CL&P will not seek to recover this non-recurring amount in its rates, which is approximately $17.9 million after-tax, or $0.10 per share.

For the distribution segment of our Regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric GWh sales, as well as total sales and percentage changes, and Yankee Gas firm natural gas sales and percentage changes in million cubic feet for 2011, as compared to the same period in 2010, on an actual and weather normalized basis (using a 30-year average), is as follows:

	For the Year Ended December 31, 2011 Compared to 2010			
	CL&P	**PSNH**	**WMECO**	**Total Electric**
Electric				

	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Decrease	Sales (GWh)		Percentage Decrease	W No Pe D
Residential	(1.0)%	- %	(1.1)%	(0.8)%	(0.6)%	- %	14,766	14,913	(1.0)%	
Commercial	(2.0)%	(0.8)%	0.2%	1.1%	(1.5)%	(0.5)%	14,301	14,506	(1.4)%	
Industrial	(2.2)%	(1.2)%	(0.2)%	1.4%	(0.9)%	(0.1)%	4,418	4,481	(1.4)%	
Other	(0.8)%	(0.8)%	(4.3)%	(4.3)%	(0.6)%	(0.6)%	327	330	(1.0)%	
Total	(1.5)%	(0.5)%	(0.4)%	0.4%	(1.0)%	(0.2)%	33,812	34,230	(1.2)%	

	For the Year Ended December 31, 2011 Compared to 2010			
Firm Natural Gas	**Sales (million cubic feet)** [1]		**Percentage Increase**	**Weather Normalized Percentage Increase/ (Decrease)**
Residential	13,508	13,403	0.8%	(3.2)%
Commercial	17,175	15,137	13.5%	9.8%
Industrial	16,197	14,866	8.9%	8.0%
Total	46,880	43,406	8.0%	5.1%
Total, Net of Special Contracts (2)	38,197	35,038	9.0%	5.4%

(1)

The 2010 sales volumes for commercial customers have been adjusted to conform to current year presentation.

(2)

Special contracts are unique to the customers who take service under such an arrangement and generally specify the amount of distribution revenue to be paid to Yankee Gas regardless of the customers usage.

Actual retail electric sales for all three electric companies were lower in 2011 compared to 2010 due primarily to milder weather in the summer of 2011, compared to warmer than normal weather in the summer of 2010. In 2011, cooling degree days in Connecticut and western Massachusetts were 20.9 percent lower than 2010, and in New Hampshire, cooling degree days were 23.7 percent lower than

2010. For WMECO, the fluctuations in retail electric sales no longer impact earnings as the DPU approved a sales decoupling plan effective February 1, 2011. Under this decoupling plan, WMECO now has an established level of baseline distribution delivery service revenues of $125.6 million that it is able to recover, which effectively breaks the relationship between kWhs consumed by customers and revenues recognized.

On a weather-normalized basis, total retail electric sales decreased slightly in 2011, as compared to 2010. We believe the weather-normalized commercial sales for CL&P and WMECO decreased in 2011, compared to 2010, due to the slow economic recovery in these service areas. PSNH commercial sales increased in 2011 due to one large self-generating customer who experienced multiple generation outages and relied on PSNH for energy. Industrial sales for both CL&P and WMECO decreased in 2011, compared to 2010, due in part to weak manufacturing activity in Connecticut and western Massachusetts. Our commercial and industrial electric sales continue to be negatively impacted by distributed generation and conservation programs.

Our firm natural gas sales are subject to many of the same influences as our retail electric sales, but have benefitted from migration of interruptible customers switching to firm service rates and the addition of gas-fired distributed generation in Yankee Gas' service territory. Actual firm natural gas sales in 2011 were 8 percent higher than 2010. Colder weather, especially in the first quarter of 2011, was a contributing factor to the higher sales. Heating degree days for 2011 in Connecticut were 6.4 percent higher than 2010. On a weather normalized basis, actual firm natural gas sales in 2011 were 5.1 percent higher than 2010.

Our expense related to uncollectible receivable balances (our uncollectibles expense) is influenced by the economic conditions of our region. Fluctuations in our uncollectibles expense are mitigated from an earnings perspective because a portion of the total uncollectibles expense for each of the electric distribution companies is recovered through each 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 (hardship customers) are fully recovered through their respective tariffs. For 2011, our total pre-tax uncollectibles expense that impacts earnings was $11.7 million, as compared to $23.4 million in 2010. The improvement in 2011 uncollectibles expense was due in part to continued enhanced accounts receivable collection efforts and credit monitoring.

NU Parent and Other Companies: NU parent and other companies (which includes our competitive businesses held by NU Enterprises) recorded net expenses of $25.7 million, or $0.14 per share, in 2011, compared with earnings of $3.9 million, or $0.03 per share, in 2010. In 2011, excluding merger-related costs of $11.3 million, or $0.06 per share, NU parent and other companies recorded net expenses of $14.4 million, or $0.08 per share. In 2010, results included a non-recurring benefit of $15.7 million, or $0.09 per share, associated with the settlement of tax issues and a charge of $9.4 million, or $0.06 per share, associated with merger-related costs.

Future Outlook

We are not providing stand-alone EPS guidance in 2012 due to our pending merger with NSTAR. However, we expect that a number of key factors will negatively impact earnings in 2012 as compared with 2011. They include higher untracked Pension expense, which is expected to increase after-tax expense by approximately $15 million, higher reliability-related spending by CL&P, and a higher effective tax rate for CL&P's transmission and distribution segments. We expect those factors to be partially offset by an expected increase in transmission rate base of more than $200 million by the end of 2012, lower NU parent interest costs, and the positive impact of distribution rate increases that were effective July 1, 2011 for CL&P and are expected to be effective on July 1, 2012 for Yankee Gas and PSNH.

Liquidity

Consolidated: Cash and cash equivalents totaled $6.6 million as of December 31, 2011, compared with $23.4 million as of December 31, 2010.

In 2011, our subsidiaries issued a total of $260 million in new long-term debt, excluding the refinancing of CL&P s and PSNH s PCRBs described below. On September 13, 2011, PSNH issued $160 million of first mortgage bonds that will mature on September 1, 2021 carrying a coupon rate of 3.20 percent. The net proceeds were used to repay short-term borrowings previously incurred in the ordinary course of business and for general working capital purposes. On September 16, 2011, WMECO issued $100 million of unsecured senior notes that will mature on September 15, 2021 carrying a coupon rate of 3.50 percent. The net proceeds were used to repay short-term borrowings previously incurred due largely in part to construction costs.

On April 1, 2011, CL&P remarketed $62 million of tax-exempt secured PCRBs that were subject to mandatory tender. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.25 percent and have a mandatory tender on April 1, 2012, at which time CL&P expects to remarket the bonds.

On May 26, 2011, PSNH issued $122 million of first mortgage bonds with a coupon rate of 4.05 percent and a maturity date of June 1, 2021, and used the proceeds to redeem $119.8 million of tax-exempt 1992 Series D and 1993 Series E PCRBs, each with a maturity date of May 1, 2021 and a coupon rate of 6 percent. The refinancing is expected to reduce PSNH s interest costs by approximately $2.2 million in 2012.

On October 24, 2011, CL&P issued $120.5 million of PCRBs carrying a coupon of 4.375 percent that will mature on September 1, 2028, and $125 million of PCRBs carrying a coupon of 1.25 percent that mature on September 1, 2028 and are subject to mandatory tender on September 3, 2013. The proceeds of these issuances were used to refund $245.5 million of PCRBs that carried a coupon of 5.85

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percent and had a maturity date of September 1, 2028. The refinancing is expected to reduce CL&P s interest costs by approximately $7.5 million in 2012.

In 2012, in addition to remarketing the CL&P $62 million PCRBs, NU parent has a debt maturity on April 1, 2012 of $263 million, which we expect will be refinanced, and Yankee Gas has an annual sinking fund requirement of $4.3 million. Also in 2012, we expect to issue $150 million of long-term debt comprised of $100 million by WMECO and $50 million by Yankee Gas in the second half of 2012.

On November 30, 2011, the FERC granted authorization to allow CL&P to incur total short-term borrowings up to a maximum of $450 million effective January 1, 2012 through December 31, 2013. In anticipation of increasing its short-term debt availability, on February 15, 2012, CL&P filed an application with the FERC requesting authorization to increase CL&P s total short-term borrowing capacity from a maximum of $450 million to a maximum of $600 million.

Cash flows provided by operating activities in 2011 totaled $901.1 million, compared with operating cash flows of $832.6 million in 2010 and $745 million in 2009 (all amounts are net of RRB payments, which are included in financing activities on the accompanying consolidated statements of cash flows). The improved cash flows were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010 (the CL&P July 1, 2010 rate increase was deferred from customer bills until January 1, 2011), the WMECO distribution rate case decision that was effective February 1, 2011, and income tax refunds of $76.6 million in 2011 largely attributable to accelerated depreciation tax benefits, compared to income tax payments of $84.5 million in 2010. Offsetting these benefits was a contribution of $143.6 million made into our Pension Plan in 2011, compared to $45 million in 2010, and approximately $157 million of cash disbursements made in 2011 associated with Tropical Storm Irene and the October snowstorm. The increase in operating cash flows from 2009 to 2010 was due primarily to the absence in 2010 of costs incurred at PSNH and WMECO related to the major ice storm in December 2008 that were paid in the first quarter of 2009, a decrease in Fuel, Materials and Supplies attributable to a $31.8 million reduction in coal inventory levels at the PSNH generation business as ordered by the NHPUC, and increases in amortization on regulatory deferrals primarily attributable to 2009 activity within PSNH s ES and CL&P s CTA tracking mechanisms where such costs exceeded revenues resulting in an unfavorable cash flow impact in 2009. Offsetting these favorable cash flow impacts was a $45 million contribution made into our Pension Plan in September 2010.

On a stand-alone basis, 2012 cash flows provided by operating activities, net of RRB payments, are expected to be lower than in 2011 due primarily to approximately $50 million more in Pension Plan contributions than in 2011 and approximately $27 million in bill credits provided to CL&P residential customers in February 2012. In 2012, cash payments for Tropical Storm Irene and the October storm costs are estimated to be approximately $160 million, as compared to 2011 payments of approximately $157 million.

A summary of the current credit ratings and outlooks by Moody's, S&P and 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	Watch-Positive	BBB	Watch-Positive
CL&P	A2	Stable	A-	Watch-Positive	A-	Positive
PSNH	A3	Stable	A-	Watch-Positive	A-	Stable
WMECO	Baa2	Stable	BBB+	Watch-Positive	BBB+	Stable

On April 18, 2011, Fitch raised PSNH's senior secured rating to A- from BBB+ to better reflect the firm's notching policy for senior secured debt. On the same day, Fitch raised its outlook on CL&P to positive from stable in part to reflect improved cash flow metrics. On May 16, 2011, S&P raised all of its corporate credit ratings and debt ratings on NU and its regulated utilities by one notch due primarily to improved financial metrics at the companies. S&P maintained its Watch-Positive outlook pending consummation of NU s merger with NSTAR. On July 14, 2011, Fitch affirmed its existing ratings and outlooks of NU parent, CL&P, PSNH and WMECO. There were no changes to Moody s ratings or outlooks for NU or its subsidiaries in 2011.

We paid common dividends of $194.6 million in 2011, compared with $180.5 million in 2010 and $162.4 million in 2009. This reflects an increase of approximately 7.3 percent in our common dividend beginning in the first quarter of 2011. On February 14, 2012, our Board of Trustees declared a quarterly common dividend of $0.29375 per share, payable on March 30, 2012 to shareholders of record as of March 1, 2012, which equates to $1.175 per share on an annualized basis. The dividend represented an increase of 6.8 percent over the $0.275 per share quarterly dividend paid in 2011. Assuming our pending merger with NSTAR closes in 2012 after NSTAR pays its March 30, 2012 dividend of $0.45 per share, the terms of the merger agreement would require NU's first quarterly dividend paid after the merger to be at least $0.343 per share, or at least $1.372 per share on an annualized basis.

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 state statute, 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 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. The merger agreement requires that our first quarterly dividend per common share paid after the closing of the merger be increased to an amount that is at least equal, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing. We do not expect the restrictions will prevent NU from meeting its obligations under the merger agreement.

In 2011, CL&P, PSNH, WMECO, and Yankee Gas paid $243.2 million, $58.8 million, $26.3 million, and $38.2 million, respectively, in common dividends to NU parent. In 2011, NU parent made equity contributions to CL&P, PSNH, WMECO, and Yankee Gas of $6.7 million, $120 million, $91.8 million, and $8.5 million, 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, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. A summary of our cash capital expenditures by company for the years ended December 31, 2011, 2010, and 2009 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars)	**2011**		**2010**		**2009**	
CL&P	$	424.9	$	380.3	$	435.7
PSNH		241.8		296.3		266.4
WMECO		238.0		115.2		105.4
Yankee Gas		98.2		82.5		54.8
NPT		24.9		7.5		-
Other		48.9		72.7		45.8
Total	$	1,076.7	$	954.5	$	908.1

The increase in our cash capital expenditures was the result of higher transmission segment cash capital expenditures of $150.6 million, primarily at WMECO and NPT, as well as higher capital expenditures at Yankee Gas related to the WWL Project.

Proceeds from Sale of Assets in 2011 of $46.8 million included on the accompanying consolidated statement of cash flows related to the sale of certain CL&P transmission assets. For further information, see Business Development and Capital Expenditures - Transmission Segment - Other in this *Management's Discussion and Analysis*.

As of December 31, 2011, NU parent had $17.9 million of LOCs issued for the benefit of certain subsidiaries (including $4 million for CL&P and $5.4 million for PSNH) and $256 million of short-term borrowings outstanding under its $500 million unsecured revolving credit facility. The weighted-average interest rate on these short-term borrowings as of December 31, 2011 was 2.2 percent, based on a variable rate plus an applicable margin based on NU parent's credit ratings. NU parent had $226.1 million of borrowing availability on this facility as of December 31, 2011.

CL&P, PSNH, WMECO, and Yankee Gas are parties to a joint unsecured revolving credit facility in a nominal aggregate amount of $400 million. As of December 31, 2011, CL&P and Yankee Gas had short-term borrowings outstanding under this facility of $31 million and $30 million, respectively, leaving $339 million of aggregate borrowing capacity available. The weighted-average interest rate on these short-term borrowings as of December 31, 2011 was 3.1 percent (4.03 percent for CL&P), which is based on a variable rate plus an applicable margin based on CL&P and Yankee Gas respective credit ratings.

We will continue to monitor availability of our credit facilities to assure that we have an adequate borrowing capacity.

Our credit facilities and 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 a consolidated debt to total capitalization ratio. As of December 31, 2011, all such companies were in compliance with these covenants. Refer to Note 8, Short-Term Debt, and Note 9, 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.

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 $1.2 billion in 2011, $1 billion in 2010, and $969.2 million in 2009. These amounts included $51.9 million in 2011, $68.7 million in 2010, and $52.7 million in 2009 related to our corporate service companies, NUSCO and RRR.

Regulated Companies: Capital expenditures for the Regulated companies totaled $1.2 billion ($467.2 million for CL&P, $291.7 million for PSNH, and $290.3 million for WMECO) in 2011.

Transmission Segment: Transmission segment capital expenditures increased by $198.5 million in 2011, as compared with 2010, due primarily to increases at WMECO related to the construction of GSRP. A summary of transmission segment capital expenditures by company in 2011, 2010 and 2009 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2011**	**2010**	**2009**
CL&P	$ 128.6	$ 107.2	$ 163.0
PSNH	68.1	49.1	59.4
WMECO	236.8	95.2	67.7
NPT	25.9	9.4	1.7
Totals	$ 459.4	$ 260.9	$ 291.8

NEEWS: GSRP, a project that involves the construction of 115 KV and 345 KV overhead lines from Ludlow, Massachusetts to Bloomfield, Connecticut, is the first, largest and most complicated project within the NEEWS family of projects. On September 13, 2011, CL&P and WMECO received the required permit from U.S. Army Corps of Engineers allowing them to commence full construction on GSRP. The $718 million project is expected to be placed in service in late 2013. As of December 31, 2011, the project was approximately 50 percent complete.

The Interstate Reliability Project, which includes CL&P s construction of an approximately 40-mile, 345 KV overhead line from Lebanon, Connecticut to the Connecticut-Rhode Island border in Thompson, Connecticut where it will connect to transmission enhancements being constructed by National Grid, is our second major NEEWS project. In August 2010, ISO-NE reaffirmed the need for the Interstate Reliability Project, which we expect to place in service in late 2015 at a cost of $218 million. On December 23, 2011, CL&P filed a siting application with the Connecticut Siting Council to build the Connecticut section of the Interstate Reliability Project. In early 2012, National Grid is expected to file siting applications with regulators in Massachusetts and Rhode Island to build its sections of the project. The late 2015 expected in-service date assumes that all siting application approvals will be received from all three states in late 2013 with construction commencing in late 2013 or early 2014.

The Central Connecticut Reliability Project, which involves construction of a $301 million new 345 KV overhead line from Bloomfield, Connecticut to Watertown, Connecticut, is the third major part of NEEWS. In March 2011, ISO-NE announced that it would review the Central Connecticut Reliability Project along with other central Connecticut projects as part of a study known as the Greater Hartford Central Connecticut Study. We expect ISO-NE to issue preliminary need results and transmission solutions in 2013.

Included as part of NEEWS are costs for associated reliability related projects, all of which have received siting approval and most of which are under construction. These projects began going into service in 2010 and will continue to go into service through 2013.

Through December 31, 2011, CL&P and WMECO had capitalized $132.6 million and $334.7 million, respectively, in costs associated with NEEWS, of which $33.9 million and $197.8 million, respectively, were capitalized in 2011. The total expected cost of NU s share of NEEWS is approximately $1.3 billion, of which $646 million and $616 million relate to CL&P and WMECO, respectively.

On May 27, 2011, the FERC issued an order accepting CL&P s and WMECO s filing requesting changes to the ISO-NE Tariff in order to include 100 percent of the NEEWS CWIP in regional rate base effective June 1, 2011. As a result of this order, CL&P and WMECO ceased accruing AFUDC on NEEWS CWIP as of June 1, 2011, and NU s local customers will receive appropriate credits for the return on CWIP they have paid.

Northern Pass: On October 4, 2010, NPT and Hydro Renewable Energy, a subsidiary of HQ, entered into a TSA in connection with the Northern Pass transmission project, which will be constructed by NPT. Northern Pass is a planned HVDC transmission line from the Québec-New Hampshire border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire. Northern Pass will interconnect at the Québec-New Hampshire border with a planned HQ HVDC transmission line.

Under the terms of the TSA, which was accepted by the FERC without modification in February 2011, NPT will sell to HQ affiliate Hydro Renewable Energy 1,200 MW of firm electric transmission rights over the Northern Pass for a 40-year term and charge cost-based rates. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project, and during commercial operation, an ROE equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent. The TSA rates will be based on a capital structure for NPT of 50 percent debt and 50 percent equity. During the development and the construction phases under the TSA, NPT will be recording non-cash AFUDC earnings.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE, which seeks permission to construct and maintain facilities that cross the U.S.-Canada border in New Hampshire and connect to HQ TransÉnergie's facilities in Québec. The DOE held seven meetings in New Hampshire in mid-March 2011 seeking public comment. In response to concerns raised at these meetings, NPT revised its application to request additional time during the public comment period to allow NPT to review alternative routes. On June 15, 2011, the DOE extended the scoping comment period for at least forty-five days after NPT files an alternative route with the DOE. Certain environmental studies will need to be completed in order to obtain DOE permits. We expect construction to begin in 2014 and the project to be completed in the fourth quarter of 2016.

On February 8, 2012, the New Hampshire legislature passed a bill that could potentially prohibit the use of eminent domain for the development of any non-reliability electric transmission projects, such as Northern Pass. The bill is currently awaiting action by the

New Hampshire Governor. We are reviewing the potential impact of the bill on NPT, should it be enacted, including its effect on the project's route, cost and schedule. We believe that NPT will be able to acquire the necessary rights along an acceptable route, which would make it feasible to construct the project even if the bill is enacted. Given the ultimate design needs of the project, along with siting and permit requirements, which will vary depending upon the route ultimately selected, there is a possibility for further delay in commencement of construction.

We currently estimate that NU's 75 percent share of the costs of the Northern Pass transmission project will be approximately $830 million and NSTAR s 25 percent share of the costs of the Northern Pass transmission project will be approximately $280 million, for a combined total expected cost of approximately $1.1 billion (including capitalized AFUDC). Through December 31, 2011, we capitalized $37 million in costs associated with NPT.

Other: On May 31, 2011, CL&P and the Connecticut Transmission Municipal Electric Energy Cooperative (CTMEEC), a non-profit municipal joint action transmission entity formed by several Connecticut municipal electric utilities, completed the sale by CL&P to CTMEEC of a segment of high voltage transmission lines built by CL&P in the town of Wallingford, Connecticut. The assets were sold at their net book value of $42.5 million, plus reimbursement of closing costs. CL&P is operating and maintaining the lines under an operations and maintenance agreement with CTMEEC. The transaction did not include the transfer of land or equipment not related to electric transmission service. The transaction did not impact our five-year capital plan and is already reflected in CL&P s transmission rate base forecasts.

Distribution Segment: A summary of distribution segment capital expenditures by company for 2011, 2010 and 2009 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2011**	**2010**	**2009**
CL&P:			
Basic Business	$ 166.6	$ 126.2	$ 104.6
Aging Infrastructure	112.3	104.0	104.1
Load Growth	59.6	75.2	74.3
Total CL&P	338.5	305.4	283.0
PSNH:			
Basic Business	47.7	41.2	55.5
Aging Infrastructure	25.3	19.5	17.8
Load Growth	25.8	23.1	25.5
Total PSNH	98.8	83.8	98.8
WMECO:			
Basic Business	24.2	17.5	21.5
Aging Infrastructure	11.5	10.5	12.2
Load Growth	6.1	5.1	4.0
Total WMECO	41.8	33.1	37.7
Total - Electric Distribution (excluding Generation)	479.1	422.3	419.5
Yankee Gas	102.8	94.6	59.6

Other		1.0		2.0		0.6
Total Distribution		582.9		518.9		479.7
PSNH Generation:						
Clean Air Project		101.1		149.7		119.3
Other		23.7		27.4		25.7
Total PSNH Generation		124.8		177.1		145.0
WMECO Generation		11.7		10.1		-
Total Distribution Segment	$	719.4	$	706.1	$	624.7

For the electric distribution business, basic business includes the relocation of plant, the purchase of meters, tools, vehicles, and information technology. Aging infrastructure relates to the planned replacement of overhead lines, plant substations, transformer replacements, and underground cable replacement. Load growth includes requests for new business and capacity additions on distribution lines and substation overloads.

The Clean Air Project is a wet scrubber project that PSNH constructed and placed in service at its Merrimack Station in September 2011, the cost of which will be recovered through PSNH's ES rates under New Hampshire law. By November 2011, both of Merrimack Station s coal-fired units were integrated with the scrubber, which is reducing emissions from the units. We expect finalization of project activities, including water discharge enhancements, in mid-2012 at a cost of approximately $422 million.

On August 12, 2009, the DPU authorized WMECO to install up to 6 MW of solar energy generation in its service territory at an estimated cost of $41 million by the end of 2012. In October 2010, WMECO completed development of a 1.8 MW solar generation facility on a site in Pittsfield, Massachusetts. The full cost of this project was $9.4 million. In December 2011, WMECO completed development of a 2.3 MW solar generation facility on a 12-acre brownfield site in Springfield, Massachusetts. The full cost of the Springfield project was $11.4 million. WMECO is continuing its evaluation of sites suitable for development of the remaining 1.9 MW of the authorized 6 MW of capacity.

Yankee Gas' WWL Project, a 16-mile natural gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of its LNG plant, was placed in service in November 2011. Project costs totaled approximately $54 million, $3.6

million below the previous estimate of $57.6 million. Pursuant to the June 29, 2011 rate case decision, the WWL Project was included in Yankee Gas rate base upon entering service.

Projected Capital Expenditures and Rate Base Estimates: Excluding the impacts of the pending merger with NSTAR, a summary of the projected capital expenditures for the Regulated companies' electric transmission segment and their distribution segment (including generation) by company for 2012 through 2016, including our corporate service companies' capital expenditures on behalf of the Regulated companies, is as follows:

	Year					
(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**2012-2016 Total**
CL&P Transmission	$ 174	$ 108	$ 255	$ 245	$ 55	$ 837
PSNH Transmission	66	125	142	94	41	468
WMECO Transmission	193	132	111	73	1	510
NPT	40	22	178	238	334	812
Subtotal Transmission	$ 473	$ 387	$ 686	$ 650	$ 431	$ 2,627
CL&P Distribution:						
Basic Business	$ 129	$ 121	$ 113	$ 114	$ 112	$ 589
Aging Infrastructure	119	101	88	90	92	490
Load Growth	67	63	73	67	72	342
Total CL&P Distribution	315	285	274	271	276	1,421
PSNH Distribution:						
Basic Business	52	49	49	50	48	248
Aging Infrastructure	29	24	28	26	25	132
Load Growth	31	37	33	40	39	180
Total PSNH Distribution	112	110	110	116	112	560
WMECO Distribution:						
Basic Business	17	16	18	18	19	88
Aging Infrastructure	15	16	16	16	16	79
Load Growth	7	7	6	6	6	32
Total WMECO Distribution	39	39	40	40	41	199
Subtotal Electric Distribution	$ 466	$ 434	$ 424	$ 427	$ 429	$ 2,180
PSNH Generation:						
Clean Air Project	$ 21	$ 2	$ -	$ -	$ -	$ 23
Other	13	26	29	34	34	136
Total PSNH Generation	34	28	29	34	34	159
CL&P Generation	11	23	11	-	-	45
WMECO Generation	19	10	10	10	-	49
Subtotal Generation	$ 64	$ 61	$ 50	$ 44	$ 34	$ 253
Yankee Gas Distribution:						
Basic Business	$ 26	$ 27	$ 28	$ 29	$ 30	$ 140

Aging Infrastructure		48		50		50		52		53		253
Load Growth		20		46		47		35		23		171
Total Yankee Gas Distribution	$	94	$	123	$	125	$	116	$	106	$	564
Corporate Service Companies	$	44	$	52	$	36	$	30	$	29	$	191
Total	$	1,141	$	1,057	$	1,321	$	1,267	$	1,029	$	5,815

Actual capital expenditures could vary from the projected amounts for the companies and periods above. Economic conditions in the northeast could impact the timing of our major capital expenditures. Most of these capital expenditure projections, including those for NPT, assume timely regulatory approval, which in most cases requires extensive review. The amounts above assume that we receive favorable responses from regulators to our proposed capital program and that our major transmission initiatives, some of which have not yet been filed with regulators, are approved in a timely manner. Delays in or denials of those approvals could reduce the levels of expenditures and associated rate base.

Based on the 2011 actual and 2012 through 2016 projected capital expenditures, the 2011 actual and 2012 through 2016 projected transmission, distribution and generation rate base as of December 31 of each year are as follows:

	Year					
(Millions of Dollars)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
CL&P Transmission	$ 2,100	$ 2,149	$ 2,091	$ 2,211	$ 2,424	$ 2,450
PSNH Transmission	390	407	524	654	707	721
WMECO Transmission	467	615	722	747	853	814
NPT	-	-	-	-	-	804
Total Transmission	2,957	3,171	3,337	3,612	3,984	4,789
CL&P Distribution	2,603	2,726	2,826	2,932	3,019	3,114
PSNH Distribution	836	888	959	1,008	1,065	1,108
WMECO Distribution	423	434	442	446	451	455
Total Electric Distribution	3,862	4,048	4,227	4,386	4,535	4,677
CL&P Generation	-	9	29	35	31	28
PSNH Generation	759	726	683	673	663	652
WMECO Generation	18	31	37	43	48	43
Total Generation	777	766	749	751	742	723
Yankee Gas Distribution	754	771	812	866	987	1,042
Total	$ 8,350	$ 8,756	$ 9,125	$ 9,615	$ 10,248	$ 11,231

<u>Transmission Rate Matters and FERC Regulatory Issues</u>

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, serves as the regional transmission organization for New England. 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: Our transmission rates recover our total transmission revenue requirements, ensuring that we recover all regional and local revenue requirements for providing transmission service. These rates provide for annual reconciliations to actual costs. The difference between billed and actual costs is deferred for future recovery from, or refund to, customers. As of December 31, 2011, we were in a total net overrecovery position of $31.4 million, which will be refunded to customers in June 2012. Of this amount, the transmission segments of CL&P, PSNH and WMECO were in an overrecovery position of $18.6 million, $1.7 million and $11.1 million, respectively.

Pursuant to a series of orders involving the ROE for regionally planned New England transmission projects, the FERC set the base ROE at 11.14 percent and approved incentives that increased the ROE to 12.64 percent for those projects that were in-service by the end of 2008. Beginning in 2009, the ROE for all regional transmission investment approved by ISO-NE is 11.64 percent, which includes the 50 basis points for joining the regional transmission organization. In addition, certain projects were granted additional ROE incentives by FERC under its transmission incentive policy. As a result, CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects. On June 28, 2011, FERC denied a motion by several New England states to reconsider the financial incentives FERC had granted the vast majority of NEEWS investments in 2008. Those incentives include an incremental 125-basis points to FERC s base New England transmission ROE, cash recovery of earnings and interest on NEEWS investments while the projects are under construction, and recovery of prudently incurred costs on projects that are abandoned.

FERC Base ROE Complaint: On September 30, 2011, several New England state attorneys general, state regulatory commissions, consumer advocates and other parties filed a joint complaint with the FERC under Sections 206 and 306 of the Federal Power Act alleging that the base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by New England transmission owners, including CL&P, PSNH and WMECO, is unjust and unreasonable. The complainants asserted that the current 11.14 percent rate, which became effective in 2006, is excessive due to changes in the capital markets and are seeking an order to reduce the rate to 9.2 percent, effective September 30, 2011.

On October 20, 2011, the New England transmission owners responded to the complaint, asking FERC to dismiss the complaint on the basis that the complainants failed to carry their burden of proof under Section 206 of the Federal Power Act to demonstrate that the existing base ROE is unjust and unreasonable. The New England transmission owners included testimony and analysis reflecting a base ROE of 11.2 percent using FERC s methodology and precedents, which they believe demonstrates that the current base ROE of 11.14 percent remains just and reasonable.

As of December 31, 2011, CL&P, PSNH, and WMECO had approximately $1.5 billion of aggregate shareholder equity invested in their transmission facilities. As a result, each 10 basis point change in the authorized base ROE would change annual consolidated earnings by an approximate $1.5 million.

Although additional testimony was submitted by the complainants and the New England transmission owners in November and December 2011, the FERC has not yet issued an order in this proceeding and we cannot predict when this proceeding will be concluded, the outcome of this proceeding, or its impact on our financial position, results of operations or cash flows.

Legislative Matters

2010 and 2011 Connecticut Legislation: In May 2010, the Connecticut Legislature approved a state budget for the 2011 fiscal year, which called for the assessment of an Economic Transition Charge to electric utility customers and the issuance by the state of Connecticut of up to $760 million of economic recovery revenue bonds that would be repaid over eight years through additional charges on electric utility customer bills. On September 29, 2010, the PURA approved a financing order for the bonds, but due primarily to legal challenges the bonds were never issued. On June 21, 2011, Governor Malloy signed legislation approving the state budget for the 2012 fiscal year that revoked the authorization for the state to issue the economic recovery revenue bonds. As a result of this change in legislation, as of July 1, 2011 CL&P customer bills do not include the charge associated with the economic recovery revenue bonds of approximately $0.0038 per kWh.

On July 1, 2011, Governor Malloy signed legislation that consolidated oversight of state energy and environmental activities into the DEEP. Effective July 1, 2011, the DPUC was replaced by PURA, which is part of the DEEP. The five commissioners of the DPUC were replaced by three directors of PURA. PURA regulates Connecticut utility rates and terms of service and oversees certain safety standards of the state s utilities, but various policy responsibilities, including the state s Integrated Resource Plan, have been assumed by a separate division within DEEP. The legislation also authorized the state s electric distribution companies, including CL&P, to build up to 10 MW of renewable generation, and authorized DEEP to study the potential for increased natural gas usage in Connecticut, including usage as a transportation fuel.

2011 New Hampshire Legislation: On March 30, 2011, the New Hampshire House of Representatives approved House Bill 648, which would preclude companies constructing non-reliability projects, such as Northern Pass, from using eminent domain to acquire property for construction of such projects. On June 2, 2011, the New Hampshire Senate voted to send House Bill 648 back to the Senate Judiciary Committee for further study. On December 8, 2011, the Senate Judiciary Committee endorsed a number of changes to the state s eminent domain legislation, but those changes did not include a ban on using eminent domain for non-reliability projects. On February 8, 2012, the New Hampshire legislature passed a bill that could potentially prohibit the use of eminent domain for development of any non-reliability electric transmission projects, such as Northern Pass. The bill is currently awaiting action by the New Hampshire Governor. For further information regarding the impacts to NPT, see Business Development and Capital Expenditures - Transmission Segment Northern Pass in this *Management's Discussion and Analysis*.

Regulatory Developments and Rate Matters

Regulatory Approvals for Pending Merger with NSTAR:

Federal: On February 10, 2012, the applicable Hart-Scott-Rodino waiting period expired. On December 21, 2011, the Federal Communications Commission extended its approval until July 7, 2012. On July 6, 2011, FERC issued its approval of the merger. On December 20, 2011, the Nuclear Regulatory Commission issued two orders approving the indirect transfer of control of the operating licenses for Yankee Nuclear Power Station and Haddam Neck Plant held by YAEC and CYAPC, which will be effected upon the merger of NU and NSTAR.

Massachusetts: On November 24, 2010, NU and NSTAR filed a joint petition requesting the DPU s approval of our pending merger. On March 10, 2011, the DPU issued an order that modified the standard of review to be applied in the review of mergers involving Massachusetts utilities from a no net harm standard to a net benefits standard, meaning that the companies must demonstrate that the pending transaction provides benefits that outweigh the costs. NU and NSTAR filed supplemental testimony and a net benefit analysis with the DPU on April 8, 2011, estimating post-transaction net savings of approximately $780 million in the first 10 years following the closing of the merger and other customer benefits. An effective date for the merger of October 1, 2011 was used in the development of the net benefit study that was filed with the DPU. Evidentiary hearings began July 6, 2011 and concluded on July 28, 2011. Briefs in the case were filed with the DPU in September and October 2011.

On July 15, 2011, the DOER filed a motion to stay the proceedings. On July 21, 2011, NU and NSTAR filed a response objecting to this motion. The DPU originally scheduled oral arguments for November 4, 2011 regarding the motion, which were further postponed during the fourth quarter of 2011 while NU, NSTAR and other parties made attempts to narrow and discuss the issues presented by the motion to stay. On January 6, 2012, oral arguments on the motion to stay were conducted. On February 15, 2012, NU and NSTAR reached comprehensive merger-related settlement agreements with both the Massachusetts Attorney General and the DOER. The first settlement agreement was reached with both the Attorney General and the DOER and covers a variety of rate-making and rate design issues, including a distribution rate freeze until 2016 for WMECO, NSTAR Electric Company and NSTAR Gas Company. The second settlement agreement was reached with the DOER and covers a variety of matters impacting the advancement of Massachusetts clean energy goals established by the Green Communities Act and Global Warming Solutions Act. Pursuant to the terms and provisions of the settlement agreements, all parties agree that the proposed merger between NU and NSTAR is consistent with the public interest and should be approved by the DPU. However, the settlement agreements allow the Attorney General and DOER to terminate their respective agreements for any reason at any time prior to approval by the DPU. All parties to the settlement agreements have requested that the DPU approve the merger on April 4, 2012.

Connecticut: In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned the DPUC (now PURA) to reconsider its earlier view from November 2010 that it lacked jurisdiction. On June 1, 2011, the

PURA issued a decision stating that it lacked jurisdiction over the merger. On June 30, 2011, the Office of Consumer Counsel filed an appeal of the PURA's final decision. NRG Energy, Inc. (NRG) and the New England Power Generators Association (NEPGA) filed similar appeals in July 2011 and filed petitions with the Connecticut Superior Court in July 2011, each requesting a declaratory ruling that the PURA has jurisdiction over the merger. On January 18, 2012, the PURA issued a final decision in which it revised its earlier declaratory ruling of June 1, 2011 that concluded it did not have jurisdiction to review the pending merger between NU and NSTAR. The final decision ruled that NU and NSTAR must now seek approval from PURA pursuant to Connecticut state law prior to completing the merger. As a result, on January 19, 2012, NU and NSTAR filed with PURA an application for approval of the merger. PURA is scheduled to issue a final decision on April 2, 2012.

If both the DPU and PURA issue acceptable decisions by such dates, we expect the merger will be consummated by April 16, 2012.

New Hampshire: On April 5, 2011, the NHPUC issued an order concluding that it does not have jurisdiction over the merger.

Maine: On May 10, 2011, the Maine Public Utilities Commission approved the merger, subject to FERC approval, which was received on July 6, 2011.

Federal:

EPA Air Toxic Standard: On December 16, 2011, the EPA issued the Mercury and Air Toxic Standards, a rule that establishes emission limits for hazardous air pollutants, including mercury and arsenic, from new and existing coal- and oil-fired electric generating units. The standards are the first to implement a nationwide emissions standard for hazardous air pollutants across all electric generating units, providing utility companies up to five years to meet the requirements. PSNH owns and operates approximately 1,000 MW of fossil fuel electric generating units, subject to these standards, including the Merrimack, Newington and Schiller stations. We believe the Clean Air Project at our Merrimack Station, along with existing equipment, enables that facility to meet at least the minimum requirements in the standards. A review of the potential impact of this rule on PSNH s other generating units is not yet complete. However, PSNH believes that the work it has undertaken in recent years to comply with New Hampshire state regulations, including the Clean Air Project, will allow it to meet the new EPA Mercury and Air Toxic Standards without significant additional investment.

EPA Proposed NPDES Permit: PSNH maintains a NPDES permit consistent with requirements of the Clean Water Act for Merrimack Station. In 1997, PSNH filed in a timely manner for a renewal of this permit. As a result, the existing permit was administratively continued. On September 29, 2011, the EPA issued a draft renewal NPDES permit for PSNH's Merrimack Station for public review and comment. The proposed permit contains many significant conditions to future operation. The proposed permit would require PSNH to install a closed-cycle cooling system (including cooling towers) at the station. The EPA estimated that the net present value cost to install this system and operate it over a 20-year period would be approximately $112 million.

On October 27, 2011, the EPA extended the initial 60-day period for public review and comment on the draft permit for an additional 90 days until February 28, 2012. The EPA does not have a set deadline to consider comments and to issue a final permit. Given the complex and unprecedented nature of many of the requirements, extensive comments to the EPA on the draft permit are anticipated from within the utility industry as well as from various environmental groups. Merrimack Station is permitted to continue to operate under its present permit pending issuance of the final permit and subsequent resolution of matters appealed by PSNH and other parties. Due to the site specific characteristics of PSNH's other fossil generating stations, we believe it is unlikely that they would have similar permit requirements imposed on them.

2011 Major Storms:

On June 1, 2011, a series of severe thunderstorms with high winds, including tornadoes, struck portions of WMECO s service territory. Approximately 17,000 WMECO electric distribution customers were without power. On June 9, 2011, another series of severe thunderstorms with high winds struck CL&P, PSNH and WMECO's service territories, resulting in power outages for approximately 260,000 electric distribution customers, including 210,000 at CL&P.

On August 28, 2011, Tropical Storm Irene caused extensive damage to our distribution system. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut.

On October 29, 2011, an unprecedented storm inundated our service territory with heavy snow causing significant damage to our distribution and transmission systems. Approximately 1.2 million of our electric distribution customers were without power at the peak of the outages, with 810,000 of those customers in Connecticut, 237,000 in New Hampshire, and 140,000 in Massachusetts. In terms of customer outages, this was the most severe storm in CL&P s history, surpassing Tropical Storm Irene; the third most severe in PSNH s history, following a December 2008 ice storm and a February 2010 wind storm; and the most severe in WMECO's history.

CL&P recorded a pre-tax charge for a storm fund reserve of $30 million to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011 as a result of the October snowstorm, and to provide contributions to certain Connecticut charitable organizations. CL&P will not seek to recover this amount in its rates.

The magnitude of the storms costs and damages met the criteria for cost deferral in Connecticut, New Hampshire, and Massachusetts and as a result, except for the CL&P storm fund reserve, the storms had no material impact on the results of operations of CL&P, PSNH and WMECO. We believe our response to all storms was prudent and therefore we believe it is probable that CL&P, PSNH and

WMECO will be allowed to recover these storm costs. Each operating company will seek recovery of its estimated deferred storm costs through its applicable regulatory recovery process.

Officials in Connecticut, New Hampshire and Massachusetts have all initiated inquiries into their state's utilities response to the October snowstorm, including CL&P, PSNH and WMECO. In addition, the PURA has included a review of the utilities' responses during Tropical Storm Irene and hired a consultant for the purposes of conducting a management audit into the emergency response programs of CL&P. These inquiries are expected to be completed in the second quarter of 2012. Connecticut Governor Malloy appointed a panel to review the preparedness of numerous state entities, including the state's utilities, in the event of a category 3 hurricane. This panel made its recommendations on January 9, 2012. Governor Malloy also hired Witt Associates to provide an independent assessment of the state's and CL&P's preparedness, response and restoration efforts during the October snowstorm. The Witt Associates Final Report was issued on December 1, 2011.Numerous committees of the Connecticut General Assembly also held hearings covering all aspects of storm response in the state. No official report is expected from these committees. We are currently evaluating several long-term initiatives to address the findings and recommendations of the panel and Witt Associates' Final Report. We believe that, if adopted, the future costs associated with these new long-term initiatives will be recovered from customers.

Connecticut CL&P:

AMI: On August 29, 2011, PURA issued a draft decision rejecting the full deployment of AMI meters to all of CL&P s customers at that time. PURA instead indicated that CL&P should begin installing AMI meters at a more moderate pace once industry standards are developed and CL&P has selected a specific technology to install. On September 2, 2011, the Commissioner of DEEP filed a motion with PURA to suspend the proceeding while the Bureau of Energy and Technology Policy conducts a process to establish an AMI policy for Connecticut, in accordance with the state law. On September 8, 2011, PURA granted DEEP s motion and suspended its proceedings. No further schedule is available at this time from either DEEP or PURA. As a result, CL&P has removed the projected AMI capital costs of approximately $257 million from its current five-year capital program.

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under SS rates, and large commercial and industrial customers who do not choose competitive suppliers are served under LRS rates. CL&P is fully recovering from customers the costs of its SS and LRS services. Effective January 1, 2012, the PURA approved a decrease to CL&P s total average SS rate of approximately 8 percent and an increase to CL&P s total average LRS rate of approximately 10.6 percent. The energy supply portion of the total average SS rate decreased from 9.732 cents per kWh to 8.443 cents per kWh while the energy supply portion of the total average LRS rate increased from 7.202 cents per kWh to 8.605 cents per kWh.

CTA and SBC Reconciliation and Rates: On March 31, 2011, CL&P filed with the PURA its 2010 CTA and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2010, total CTA revenue requirements exceeded CTA revenues by $4.5 million. For the 12 months ended December 31, 2010, the SBC revenues exceeded SBC revenue requirements by $19.8 million. On October 12, 2011, PURA approved the 2010 CTA and SBC reconciliations as filed. The decision allowed a CTA rate, effective January

1, 2012, that would recover $26.1 million during 2012, and requires CL&P to provide updated actual and projected costs when it files its requested rate adjustments for January 1, 2012. The decision also allowed an SBC rate, effective January 1, 2012, that would collect $23.7 million during 2012.

On December 22, 2011, PURA approved new CTA and SBC rates, effective January 1, 2012, using updated information provided by CL&P. Based on that updated information, the CTA rate will decrease from 0.332 cents per kWh to 0.128 cents per kWh, and the SBC will increase from 0.037 cents per kWh to 0.143 cents per kWh.

FMCC Filing: On February 4, 2011, CL&P filed with the PURA its semi-annual filing, which reconciled actual FMCC revenues and charges and GSC revenues and expenses, for the period July 1, 2010 through December 31, 2010, and also included the previously filed revenues and expenses for the January 1, 2010 through June 30, 2010 period. The filing identified a total net overrecovery of $0.3 million, which includes the remaining uncollected or non-refunded portions from previous filings. A hearing was held during the second quarter of 2011 and on June 29, 2011, the PURA issued a final decision accepting CL&P s calculations of GSC, bypassable FMCC and nonbypassable FMCC revenues and expenses for the period July 1, 2010 through December 31, 2010. On August 1, 2011, CL&P filed with the PURA its semi-annual FMCC filing for the period January 1, 2011 through June 30, 2011. The filing identified a total net overrecovery of $10.9 million for the period, which includes the remaining uncollected or non-refunded portions from previous filings. A hearing was held during the fourth quarter of 2011 and on December 28, 2011, the PURA issued a final decision accepting CL&P s calculations of GSC, bypassable FMCC and nonbypassable FMCC actual revenues and expenses for the six months reviewed in the proceeding. On February 2, 2012, CL&P filed with the PURA its semi-annual FMCC filing for the period July 1, 2011 through December 31, 2011, and also included the previously filed revenues and expenses for the January 1, 2011 through June 30, 2011 period. The filing identified a total net overrecovery of $18.7 million, which includes the remaining uncollected or non-refunded portions from previous filings. PURA has not yet set a schedule to review this filing, but we do not expect the outcome of the PURA's review to have a material adverse impact on CL&P's financial position, results of operations or cash flows.

Procurement Fee Rate Proceedings: In prior years, CL&P submitted to the PURA 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 and 2006 procurement fee in earnings. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings, through a CTA reconciliation process. On January 15, 2009, the PURA 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 PURA decision. The Court remanded the case back to the PURA for the correction of several specific errors. On February 22, 2010, the PURA appealed the Connecticut Superior Court s February 4, 2010 decision to the Connecticut Appellate Court, which then transferred the appeal to the Connecticut Supreme Court. A decision is expected from the Connecticut Supreme Court in the second half of 2012.

Connecticut - Yankee Gas:

Distribution Rates: On June 29, 2011, PURA issued a final decision in the Yankee Gas rate proceeding that it amended on September 28, 2011. The final decision approved a regulatory ROE of 8.83 percent, based on a capital structure of 52.2 percent common equity and 47.8 percent debt, approved Yankee Gas WWL Project, and also allowed for an increase for bare steel and cast iron pipe annual replacement funding, as requested by Yankee Gas. The changes were effective July 20, 2011 and will have the effect of decreasing revenues by $0.2 million for the twelve months ending June 30, 2012 and increasing revenues by $6.9 million for the twelve months ending June 30, 2013.

New Hampshire:

Distribution Rates: In March 2011, PSNH filed with the NHPUC to collect certain exogenous costs, step increases, and storm costs, as permitted by its 2010 rate case settlement. These rate increases were offset by the scheduled termination, on June 30, 2011, of a rate recoupment charge, also from the 2010 rate case settlement. During the second quarter of 2011, the NHPUC issued rate orders approving net increases in revenue requirements effective July 1, 2011 to (1) recover exogenous costs, (2) implement a step increase program for capital additions and the reliability enhancement program, and (3) allow for the recovery of the 2010 windstorm costs. Together with the scheduled termination of the rate recoupment charge, the net impact of these rate changes was a $2.4 million decrease in rates effective July 1, 2011.

ES, SCRC, and TCAM Filings: During the second quarter of 2011, PSNH filed with the NHPUC requests for ES, SCRC and TCAM rates of 8.89 cents per kWh, 1.09 cents per kWh, and 1.189 cents per kWh, respectively, to be effective July 1, 2011. On June 28, 2011, the NHPUC issued orders approving the ES and SCRC rates as filed, and on June 29, 2011, the NHPUC issued an order approving the TCAM rate as filed.

On July 26, 2011, the NHPUC ordered PSNH to file a rate proposal that would mitigate the impact of customer migration expected to occur when the ES rate is higher than market prices. On January 26, 2012, the NHPUC rejected the PSNH proposal and ordered PSNH to file a new proposal no later than June 30, 2012, addressing certain issues raised by the NHPUC.

On November 22, 2011, the NHPUC opened a docket to place the Clean Air Project into ES rates, including conducting a prudence review and establishing temporary rates. Hearings are scheduled on temporary rates for March 12 and 13, 2012. Following hearings on temporary rates, it is expected that recovery of costs of the Clean Air Project will begin during the second quarter of 2012. No formal schedule for the comprehensive prudence review or for permanent rates has been established.

On December 30, 2011, the NHPUC issued an order establishing an ES rate of 8.31 cents per kWh, effective January 1, 2012, as opposed to the previous 8.89 cents per kWh.

In September 2011, PSNH filed a petition with the NHPUC requesting a change in its SCRC annual rate for the period January 1, 2012 through December 31, 2012. In mid-December 2011, PSNH filed updated values, which set the proposed SCRC rate at 1.23 cents per kWh. In late December 2011, the NHPUC approved the SCRC rate as filed.

ES and SCRC Reconciliation: On an annual basis, PSNH files with the NHPUC an ES/SCRC cost reconciliation filing for the preceding year. On April 29, 2011, the NHPUC approved a settlement between PSNH and the NHPUC staff regarding PSNH s 2009 ES/SCRC reconciliation filing. The settlement did not have a material impact on PSNH's financial position, results of operations or cash flows. On May 2, 2011, PSNH filed its 2010 ES/SCRC reconciliation with the NHPUC, whose evaluation includes a prudence review of PSNH's generation and power purchase activities. In November 2011, PSNH and the NHPUC staff reached a settlement regarding PSNH s 2010 ES/SCRC reconciliation filing. The settlement did not have a material impact on PSNH's financial position, results of operations or cash flows. The NHPUC held a hearing on the settlement in late November 2011, and issued an order approving the settlement on January 26, 2012.

As of December 31, 2011, PSNH had ES and SCRC regulatory assets of $17.3 million and $1.5 million, respectively, which are being recovered from customers in 2012.

Merrimack Clean Air Project: On July 7, 2009, the New Hampshire Site Evaluation Committee (NHSEC) determined that PSNH's Clean Air Project was not subject to the NHSEC s review as a sizeable addition to a power plant under state law. The NHSEC upheld its decision in an order dated January 15, 2010, denying requests for rehearing. This order was appealed to the New Hampshire Supreme Court on February 23, 2010. On July 21, 2011, the New Hampshire Supreme Court ruled that the appellants lacked standing to file their original action with the NHSEC, and that the NHSEC erred in entertaining the appellants' filing. The Court vacated the NHSEC s decision, confirming PSNH's position that NHSEC approval was not necessary.

Massachusetts:

Basic Service Rates: In 2011, WMECO s fixed basic service rates ranged from 6.993 cents per kWh to 6.998 cents per kWh for residential customers, 7.498 cents per kWh to 8.006 cents per kWh for small commercial and industrial customers, and 6.958 cents per kWh to 7.450 cents per kWh for medium and large commercial and industrial customers. Effective January 1, 2012, WMECO s rates for all basic service customers increased to reflect the basic service solicitations conducted by WMECO in November 2011. WMECO s fixed basic service rates for residential customers increased to 7.715 cents per kWh, fixed rates for small commercial and industrial customers increased to 8.238 cents per kWh and fixed rates for large commercial and industrial customers increased to 8.451 cents per kWh. The fixed price increased by 0.753 cents per kWh for street lighting customers to 6.403 cents per kWh.

Critical Accounting Policies

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 significant matters relating to critical accounting policies. Our critical accounting policies are discussed below. See the combined notes to our consolidated financial statements for further information concerning the 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, regulatory precedent. 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 that 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 the determination is made.

For further information, see Note 2, 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 regularly throughout the month. Billed revenues are based on these meter readings and the majority of recorded annual 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 estimates, and an estimated amount of unbilled revenues is recorded.

Unbilled revenues represent an estimate of electricity or natural 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 there is a change in estimates and under other circumstances.

The Regulated companies estimate unbilled revenues monthly using the daily load cycle method. The daily load cycle 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 month load, net of delivery losses, to estimate unbilled sales. Unbilled revenues are estimated by first allocating sales to the respective customer classes and then applying an average rate by customer class 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.

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

Pension and PBOP: Our subsidiaries participate in a Pension Plan covering certain of our regular employees and in a 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 cost is based on several significant assumptions. We evaluate these assumptions at least annually and adjust them as necessary. Changes in these assumptions could have a material impact on our financial position, results of operations or cash flows.

Pre-tax net periodic pension expense (excluding SERP) for the Pension Plan was $127.7 million, $80.4 million and $39.7 million for the years ended December 31, 2011, 2010 and 2009, respectively. The pre-tax net PBOP Plan expense was $43.6 million, $41.6 million and $37.2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

We develop key assumptions for purposes of measuring the plans liabilities as of December 31 and expenses for the subsequent year. These assumptions include the long-term rate of return on plan assets, discount rate, compensation/progression rate, and health care cost trend rates and are discussed below.

Long-Term Rate of Return on Plan Assets: In developing this assumption, we consider historical and expected returns and input from our actuaries and consultants. Our expected long-term rate of return on assets is based on assumptions regarding target asset allocations and corresponding expected rates of return for each asset class. We routinely review the actual asset allocations and periodically rebalance the investments to the targeted asset allocations when appropriate. We used an aggregate expected long-term rate of return assumption of 8.25 percent on Pension and PBOP Plan assets as of December 31, 2011.

Discount Rate: Payment obligations related to the Pension Plan and PBOP Plan are discounted at interest rates applicable to the timing of the plans cash flows. The discount rate that is utilized in determining the pension and PBOP obligations is based on a yield-curve approach. This approach is based on a population of bonds with an average rating of AA based on bond ratings by Moody s, S&P and Fitch, and uses bonds with above median yields within that population. The discount rates determined on this basis are 5.03 percent for the Pension Plan and 4.84 percent for the PBOP Plan as of December 31, 2011 and 5.57 percent and 5.28 percent for the respective plans as of December 31, 2010.

Compensation/Progression Rate: This assumption reflects the expected long-term salary growth rate, which impacts the estimated benefits that pension plan participants receive in the future. We used a compensation/progression rate of 3.5 percent as of December 31, 2011 and 2010, which reflects our current expectation of future salary increases, including consideration of the levels of increases built into union contracts.

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

We determine the expected return on plan assets by applying our assumed rate of return to a four-year rolling average fair values, which reduces year-to-year volatility. This calculation recognizes investment gains or losses over a four-year period from the years in which they occur. Investment gains or losses for this purpose are the difference between the calculated expected return and the actual return or loss based on the change in the fair value of assets during the year. As of December 31, 2011, investment losses that remain to be reflected in the calculation of plan assets over the next four years were $369 million and $5.8 million for the Pension Plan and PBOP Plan, respectively. As investment gains and losses are reflected in the average plan asset fair values, they are subject to amortization with other unrecognized actuarial gains or losses. The plans currently amortize unrecognized actuarial gains or losses as a component of pension and PBOP expense over the average future employee service period of approximately 10 and 9 years, respectively. As of December 31, 2011, the net unrecognized actuarial losses on the Pension and PBOP Plan liabilities, subject to amortization, were $819.3 million and $202.5 million, respectively.

Forecasted Expenses and Expected Contributions: Based upon the assumptions and methodologies discussed above, we estimate that forecasted expense for the Pension Plan and PBOP Plan will be $167.9 million and $44.7 million, respectively, in 2012. Pension and PBOP expense for subsequent years will depend on future investment performance, changes in future discount rates and other assumptions, and various other factors related to the populations participating in the plans. Pension and PBOP expense charged to earnings is net of the 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. NU's policy is to annually fund the Pension Plan in an amount at least equal to what will satisfy the requirements of ERISA, as amended by the PPA, and the Internal Revenue Code. NU's Pension Plan has historically been well funded, and a contribution was not required to be made from 1991 until the third quarter of 2010, when PSNH made a contribution to the plan of $45 million. NU made contributions totaling $143.6 million in 2011, $112.6 million of which were contributed by PSNH. Our Pension Plan funded ratio (the value of plan assets divided by the funding target in accordance with the requirements and guidelines of the PPA) was 80 percent as of January 1, 2011. We currently estimate that quarterly contributions aggregating to a total of $197.3 million will be made in 2012.

Sensitivity Analysis: The following represents the hypothetical increase to the Pension Plan s (excluding SERP) and PBOP Plan s reported annual 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	**2011**		**2010**		**2011**		**2010**	
Lower long-term rate of return	$	10.3	$	10.7	$	1.3	$	1.2
Lower discount rate	$	14.2	$	13.4	$	2.3	$	2.2
Higher compensation increase	$	6.5	$	6.1	$	N/A		N/A

Pension Plan Contributions Discount Rate Sensitivity Analysis: Fluctuations in the average discount rate used to calculate expected Pension Plan contributions can have a significant impact on the amount of Pension Plan contributions estimated to be required. As of December 31, 2011, the average discount rate (segment rate) used to calculate funding target and to determine the expected Pension Plan contributions totaling $590 million for the period 2013 through 2016 was approximately 5.5 percent. If this discount rate was decreased by 50 basis points, all other items remaining constant, then the expected aggregate contributions would increase to approximately $710 million for the period 2013 through 2016. In addition, the market performance of existing plan assets, the valuation of the plan's liabilities, and a variety of other factors would impact the Pension Plan contributions.

Health Care Cost: The health care cost trend assumption used to project increases in medical costs was 7 percent for determining 2011 PBOP Plan expense. For 2012 and 2013, the rate is 7 percent, subsequently decreasing one half percentage point per year to an ultimate rate of 5 percent in 2017. The effect of a hypothetical increase in the health care cost trend rate by one percentage point would be to have increased service and interest cost components of PBOP Plan expense by $1.2 million in 2011, with a $16.2 million impact on the postretirement benefit obligation.

See Note 10A, Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions, to the consolidated financial statements for more information.

Goodwill and Intangible Assets: We are required to test goodwill balances for impairment at least annually by applying a fair value-based test that requires us to use estimates and judgment. We have selected October 1st of each year as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount of the goodwill. If goodwill were deemed to be impaired, it would be written down in the current period to the extent of the impairment.

We determine the discount rate using the capital asset pricing model methodology. This methodology uses a weighted average cost of capital in which the ROE is developed using risk-free rates, equity 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 may change from year to year as it is based on external market conditions.

We performed an impairment analysis as of October 1, 2011 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 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 a discounted cash flow methodology and two market approaches that analyze comparable companies or transactions. This evaluation 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, long-term earnings and merger multiples of comparable companies.

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 for financial reporting and income tax return reporting purposes. 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.

A reconciliation of expected tax expense at the statutory federal income tax rate to actual tax expense recorded is included in Note 11, 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 and circumstances 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 (including information gained from those examinations), 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 financial position, results of operations 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 estimates of environmental liabilities could have a significant impact on earnings. We estimate these liabilities based on findings through various phases of the assessment, considering the most likely action plan from a variety of available options (ranging from no action to full site remediation and long-term monitoring), current site information from our site assessments, remediation estimates from third party engineering and remediation contractors, and our prior experience in remediating contaminated sites. Our estimates incorporate currently enacted state and federal environmental laws and regulations and data released by the EPA and other organizations. The estimates associated with each possible action plan are judgmental in nature partly because there are usually several different remediation options from which to choose. Our estimates are subject to revision in future periods based on actual costs or new information from other sources, including the level of contamination at the site recently enacted laws and regulations or a change in estimates due to certain economic factors.

For further information, see Note 12A, Commitments and Contingencies - Environmental Matters, to the consolidated financial statements and *Other Matters* below.

Fair Value Measurements: We follow 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). We have applied this 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.

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 and assumptions are made.

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. When quoted prices in active markets for the same or similar instruments are not available, we value derivative contracts using models that incorporate both observable and unobservable inputs. 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. 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 our estimates of nonperformance risk, including credit risk.

For further information, 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 energy and energy related products would impact earnings.

For further information on derivative contracts and marketable securities, see Note 1J, Summary of Significant Accounting Policies - Derivative Accounting, Note 4, Derivative Instruments, and Note 5, Marketable Securities, to the consolidated financial statements.

Other Matters

Environmental Matter: HWP continues to investigate the potential need for additional remediation at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal utility, in 1902. As of December 31, 2011, HWP had a $2.4 million reserve for estimated costs that HWP considers probable over the remaining life of the remediation term. Although a material increase to the reserve is not presently anticipated, management cannot reasonably estimate potential additional investigation or remediation costs because these costs would depend, among other things, on the nature, extent and timing of additional investigation and remediation that may be required by the MA DEP.

For further information, see Note 12A, Commitments and Contingencies - Environmental Matters, to the consolidated financial statements.

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

Contractual Obligations and Commercial Commitments: Information regarding our contractual obligations and commercial commitments as of December 31, 2011 is summarized annually through 2016 and thereafter as follows:

NU

(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**
Long-term debt maturities (a)	$ 329.3	$ 430.0	$ 275.0	$ 150.0	$ 15.4	$ 3,449.6	$ 4,649.3
Estimated interest payments on existing debt (b)	230.8	219.2	207.6	193.5	188.3	1,622.4	2,661.8
Capital leases (c)	3.0	2.6	2.2	2.2	2.0	9.5	21.5
Operating leases (d)	7.7	6.9	4.9	4.3	4.3	16.6	44.7
Funding of pension obligations (d) (h)	197.3	152.2	153.1	148.8	135.3	46.0	832.7
Funding of other postretirement benefit obligations (d)	44.7	28.3	25.5	23.8	21.0	18.6	161.9
Estimated future annual long-term contractual costs (e)	613.5	536.2	567.4	508.1	493.0	4,129.1	6,847.3
Other purchase commitments (d) (g)	1,965.5	-	-	-	-	-	1,965.5
Total (f) (i)	$ 3,391.8	$ 1,375.4	$ 1,235.7	$ 1,030.7	$ 859.3	$ 9,291.8	$ 17,184.7

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CL&P

(Millions of Dollars)	2012	2013	2014	2015	2016	Thereafter	Total
Long-term debt maturities [(a)]	$ 62.0	$ 125.0	$ 150.0	$ 100.0	$ 15.4	$ 1,891.3	$ 2,343.7
Estimated interest payments on existing debt [(b)]	126.2	126.2	126.2	116.5	114.0	1,168.3	1,777.4
Capital leases [(c)]	2.3	2.1	1.9	1.9	1.9	9.4	19.5
Operating leases [(d)]	3.2	2.8	2.6	2.6	2.6	12.0	25.8
Funding of other postretirement benefit obligations [(d)]	17.3	9.5	8.6	8.1	7.1	6.3	56.9
Estimated future annual long-term contractual costs [(e)]	282.6	324.0	362.2	352.1	349.5	2,577.1	4,247.5
Other purchase commitments [(d) (g)]	744.8	-	-	-	-	-	744.8
Total [(f) (i)]	$ 1,238.4	$ 589.6	$ 651.5	$ 581.2	$ 490.5	$ 5,664.4	$ 9,215.6

(a)

Long-term debt maturities exclude fees and interest due for spent nuclear fuel disposal costs, unamortized premiums and discounts, and net changes in fair value of hedged debt for NU.

(b)

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 2011 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.

(c)

The capital lease obligations include imputed interest for NU and CL&P.

(d)

Amounts are not included on our consolidated balance sheets.

(e)

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.

(f)

Does not include unrecognized tax benefits for NU and CL&P as of December 31, 2011, as we cannot make reasonable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities. Also does not include an NU contingent commitment of approximately $45 million to an energy investment fund, which would be invested under certain conditions, as we cannot make reasonable estimates of the periods or the investment contributions.

(g)

Amount represents open purchase orders, excluding those obligations that are included in the capital leases, operating leases and estimated future annual long-term contractual 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 2012.

(h)

These amounts represent NU's estimated minimum pension contributions to its qualified Pension Plan required under ERISA, as amended by the PPA, and the Internal Revenue Code. Contributions in 2013 through 2016 and thereafter will vary depending on many factors, including the performance of existing plan assets, valuation of the plan's liabilities and long-term discount rates, and are subject to change.

(i)

For NU, excludes other long-term liabilities, including a significant portion of the unrecognized tax benefits described above, deferred contractual obligations, environmental reserves, various injuries and damages reserves ($37.5 million), employee medical insurance reserves ($7.7 million), long-term disability insurance reserves ($11.9 million) and the ARO liability reserves as we cannot make reasonable estimates of the timing of payments. For CL&P, excludes unrecognized tax benefits described above, deferred contractual obligations, environmental reserves, various injuries and damages reserves ($26.1 million), employee medical insurance reserves ($2.4 million), long-term disability insurance reserves ($4 million) and the ARO liability reserves.

For further information regarding our contractual obligations and commercial commitments, see Note 8, Short-Term Debt, Note 9, Long-Term Debt, Note 10A, Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions, Note 12B, Commitments and Contingencies - Long-Term Contractual Arrangements, and Note 13, Leases, to the consolidated financial statements.

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.

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

RESULTS OF OPERATIONS   NORTHEAST UTILITIES AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for NU included in this Annual Report on Form 10-K for the years ended December 31, 2011, 2010 and 2009:

Comparison of 2011 to 2010:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 4,465.7	$ 4,898.2	$ (432.5)	(8.8)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	1,580.7	1,985.6	(404.9)	(20.4)
Other Operating Expenses	1,026.2	958.4	67.8	7.1
Maintenance	271.8	210.3	61.5	29.2
Depreciation	302.2	300.7	1.5	0.5
Amortization of Regulatory Assets, Net	97.1	95.7	1.4	1.5
Amortization of Rate Reduction Bonds	69.9	232.9	(163.0)	(70.0)
Taxes Other Than Income Taxes	323.6	314.7	8.9	2.8
Total Operating Expenses	3,671.5	4,098.3	(426.8)	(10.4)
Operating Income	$ 794.2	$ 799.9	$ (5.7)	(0.7)%

Operating Revenues

	For the Years Ended December 31,			
	2011	**2010**	**Increase/ (Decrease)**	**Percent**
Electric Distribution	$ 3,343.1	$ 3,802.0	$ (458.9)	(12.1)%
Natural Gas Distribution	430.8	434.3	(3.5)	(0.8)
Total Distribution	3,773.9	4,236.3	(462.4)	(10.9)
Transmission	635.4	625.6	9.8	1.6
Total Regulated Companies	4,409.3	4,861.9	(452.6)	(9.3)
Other and Eliminations	56.4	36.3	20.1	55.4
NU	$ 4,465.7	$ 4,898.2	$ (432.5)	(8.8)%

A summary of our retail electric sales and firm natural gas sales were as follows:

	For the Years Ended December 31,			
	2011	**2010**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	33,812	34,230	(418)	(1.2)%
	46,880	43,406	3,474	8.0 %

Firm Natural Gas Sales in Million Cubic Feet[(1)]				
Firm Natural Gas Sales (Net of Special Contracts)				
in Million Cubic Feet	38,197	35,038	3,159	9.0 %

(1) The 2010 sales volumes for commercial customers have been adjusted to conform to current year presentation.

Our Operating Revenues decreased in 2011, as compared to 2010, due primarily to:

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Lower electric distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower energy and supply-related costs ($365.3 million), lower CTA revenues and stranded cost recoveries ($175.3 million), lower wholesale revenues ($85.2 million) and lower retail other revenues ($37.9 million), partially offset by higher CL&P FMCC delivery-related revenues ($28.6 million), higher retail transmission revenues ($12.2 million) and higher other tracked revenues ($28.7 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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The portion of electric distribution revenues that impacts earnings increased $135.5 million due primarily to the rate case decisions that were effective during 2011.

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Improved transmission segment revenues resulting from a higher level of investment in transmission infrastructure and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses. These were partially offset by a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2011, as compared to 2010, due primarily to the following:

(Millions of Dollars)		**2011 Decrease as compared to 2010**
Lower GSC supply costs and purchased power costs, partially offset by higher other costs at CL&P	$	(323.4)
Lower energy prices, a slight increase in ES customer migration to third party suppliers and lower retail sales for PSNH's remaining ES customers		(54.3)
Lower basic/default service supply costs at WMECO		(11.7)
Lower natural gas costs at Yankee Gas		(15.1)
Other		(0.4)
	$	(404.9)

Other Operating Expenses

Other Operating Expenses increased in 2011, as compared to 2010, due primarily to:

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Higher electric distribution expenses ($52.4 million) and higher natural gas expenses ($6.9 million), primarily related to CL&P s establishment of a $30 million storm fund reserve to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011, as a result of the October 2011 snowstorm and to provide contributions to certain Connecticut charitable organizations. In addition, there were higher pension costs and higher general and administrative expenses. Partially offsetting these increases were lower costs that are recovered through distribution tracking mechanisms that have no earnings impact ($11.8 million), such as retail transmission, reliability must run and customer service expenses. In addition, there were lower transmission segment expenses ($8.5 million).

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Higher NU parent and other companies expenses ($27.3 million) were due primarily to higher costs at NU s unregulated electrical contracting business related to an increased level of work in 2011 ($19.6 million), partially offset by a decrease in costs related to NU's pending merger with NSTAR ($2.1 million).

Maintenance

Maintenance increased in 2011, as compared to 2010, due primarily to the partial amortization in 2011 of the allowed regulatory deferral, which was recorded in maintenance expense in 2010, as a result of the June 30, 2010 CL&P rate case decision ($54.9 million) and higher boiler equipment and maintenance costs at PSNH s generation business related to the absence in 2011 of insurance proceeds received in 2010 related to turbine damage, which reduced 2010 costs ($7.4 million).

Depreciation

Depreciation increased in 2011, as compared to 2010, due primarily to higher depreciation rates being used at PSNH and WMECO in 2011 as a result of distribution rate case decisions that were effective during 2011 and higher utility plant balances resulting from completed construction projects placed into service. Partially offsetting these increases was a lower depreciation rate being used at CL&P as a result of the distribution rate case decision that was effective July 1, 2010.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, increased in 2011, as compared to 2010, due primarily to lower CTA transition costs ($197.7 million) partially offset by lower retail CTA revenue ($154.6 million) at CL&P, the absence in 2011 of the impact from the 2010 Healthcare Act related to income taxes ($26 million) and increases in ES amortization ($11.4 million) and TCAM amortization ($5.9 million) at PSNH. Partially offsetting these increases was lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes at CL&P ($38.2 million) and lower amortization of the SBC balance at CL&P ($29.7 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs decreased in 2011, as compared to 2010, due to the maturity of CL&P s RRBs in December 2010 and lower principal balances on the remaining PSNH and WMECO RRBs outstanding.

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes in 2011, as compared to 2010, was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to our capital program and an increase in the tax rate, offset by a decrease in the Connecticut Gross Earnings Tax due primarily to lower transmission segment revenues and lower CTA revenues in 2011, as compared to 2010.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 231.6	$ 231.1	$ 0.5	0.2 %
Interest on RRBs	8.6	20.6	(12.0)	(58.3)
Other Interest	10.2	(14.4)	24.6	(a)
	$ 250.4	$ 237.3	$ 13.1	5.5 %

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

Interest Expense increased in 2011, as compared to 2010, due primarily to higher Other Interest in 2011, as compared to 2010, due to the prior year inclusion of a tax-related benefit, partially offset by lower Interest on RRBs in 2011, as compared to 2010, resulting from the maturity of CL&P s RRBs in December 2010 and lower principal balances on the remaining PSNH and WMECO RRBs outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**
Other Income, Net	$ 27.7	$ 41.9	$ (14.2)	(33.9)%

Other Income, Net decreased in 2011, as compared to 2010, due primarily to net losses on the NU supplemental benefit trust in 2011, compared to net gains in 2010, and the 2011 classification of C&LM and EIA incentives; partially offset by higher AFUDC related to equity funds.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**
Income Tax Expense	$ 171.0	$ 210.4	$ (39.4)	(18.7)%

Income Tax Expense decreased in 2011, as compared to 2010, due primarily to the absence in 2011 of the impact from the 2010 Healthcare Act ($25.2 million), adjustments for prior years taxes including adjustments to reconcile estimated taxes accrued to actual amounts reflected in our filed tax returns (return to provision adjustments) ($16.3 million), lower items that directly impact our tax return as a result of regulatory actions (flow-through items) ($4.6 million) and lower pre-tax earnings ($2.1 million); partially offset by higher state income taxes ($9.6 million).

Comparison of 2010 to 2009:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 4,898.2	$ 5,439.4	$ (541.2)	(9.9)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	1,985.6	2,629.6	(644.0)	(24.5)
Other Operating Expenses	958.4	1,001.2	(42.8)	(4.3)
Maintenance	210.3	234.2	(23.9)	(10.2)
Depreciation	300.7	309.6	(8.9)	(2.9)
Amortization of Regulatory Assets, Net	95.7	13.3	82.4	(a)
Amortization of Rate Reduction Bonds	232.9	217.9	15.0	6.9
Taxes Other Than Income Taxes	314.7	282.2	32.5	11.5
Total Operating Expenses	4,098.3	4,688.0	(589.7)	(12.6)
Operating Income	$ 799.9	$ 751.4	$ 48.5	6.5 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Electric Distribution	$ 3,802.0	$ 4,358.4	$ (556.4)	(12.8)%
Natural Gas Distribution	434.3	449.6	(15.3)	(3.4)
Total Distribution	4,236.3	4,808.0	(571.7)	(11.9)
Transmission	625.6	577.9	47.7	8.3
Total Regulated Companies	4,861.9	5,385.9	(524.0)	(9.7)
Other and Eliminations	36.3	53.5	(17.2)	(32.1)
NU	$ 4,898.2	$ 5,439.4	$ (541.2)	(9.9)%

A summary of our retail electric sales and firm natural gas sales were as follows:

	For the Years Ended December 31,			
	2010	**2009**	**Increase**	**Percent**
Retail Electric Sales in GWh	34,230	33,645	585	1.7%
Firm Natural Gas Sales in Million Cubic Feet [1]	43,406	42,605	801	1.9%

[1] The sales volumes for commercial customers have been adjusted to conform to current year presentation.

Our Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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Lower electric distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower GSC and supply-related FMCC charges ($574 million) and lower CL&P delivery-related FMCC ($39 million), partially offset by higher retail transmission revenues ($66 million) and higher transition cost recoveries ($48 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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The portion of electric distribution revenues that impacts earnings increased $40 million due primarily to a 1.7 percent increase in retail electric sales volume due to warmer than normal summer weather and PSNH's rate changes that were effective July 1, 2010. A decrease in natural gas revenues was due primarily to lower cost of fuel, as fuel costs are fully recovered in revenues from sales to our customers, offset by an increase in sales volume. Firm natural gas sales increased 1.9 percent in 2010 compared to 2009.

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Improved transmission segment revenues resulting from a higher level of investment in transmission infrastructure and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to the following:

(Millions of Dollars)		2010 Increase/(Decrease) as compared to 2009
Lower GSC supply costs and purchased power contract costs, partially offset by an increase in deferred fuel costs at CL&P	$	(437.4)
Lower prices on purchased natural gas at Yankee Gas		(19.7)
An increased level of ES customer migration to third party electric suppliers, partially offset by higher retail sales at PSNH		(157.4)
Lower basic service supply costs at WMECO		(34.9)
Increase in expenses due primarily to lower unregulated business wholesale contract mark-to-market gains and other loss		5.4
	$	(644.0)

Other Operating Expenses

Other Operating Expenses decreased in 2010, as compared to 2009, due primarily to:

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Lower distribution and transmission segment expenses of $66 million were due primarily to lower costs that are recovered through distribution tracking mechanisms that have no earnings impact ($65 million), such as retail transmission, reliability must run and customer service expenses, and lower uncollectibles expense at Yankee Gas ($16 million), partially offset by higher electric distribution and natural gas expenses ($22 million and $3 million, respectively), including higher pension costs and storm restoration costs, and higher transmission segment expenses ($4 million).

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Higher NU parent and other companies expenses of $22 million due primarily to costs incurred in 2010 related to NU's pending merger with NSTAR and higher pension and environmental costs.

Maintenance

Maintenance decreased in 2010, as compared to 2009, due primarily to the allowed regulatory deferral of approximately $32 million as a result of the June 30, 2010 CL&P rate case decision, of which $29.5 million was recognized as a deferral in maintenance expense, lower boiler and maintenance costs at PSNH s generation business

($12 million), offset by higher distribution segment overhead line expenses ($13 million), higher distribution segment vegetation management costs ($2 million) and higher transmission segment routine station maintenance expenses ($2 million).

Depreciation

Depreciation decreased in 2010, as compared to 2009, due primarily to a lower depreciation rate being used at CL&P as a result of the distribution rate case decision that was effective July 1, 2010, partially offset by higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net increased in 2010, as compared to 2009, due primarily to a higher recovery of CTA costs at CL&P ($39 million), higher PSNH amortization on the ES deferral and TCAM ($42 million and $11 million, respectively), and previously deferred unrecovered stranded generation costs at WMECO ($11 million), partially offset by the impact of the 2010 Healthcare Act related to the deferral of lost tax benefits that we believe are probable of recovery in future electric and natural gas distribution rates ($26 million).

Taxes Other Than Income Taxes

(Millions of Dollars)		**2010 Increase as compared to 2009**
Connecticut Gross Earnings Tax	$	8.9
Property Taxes		12.5
Use Taxes		10.4
Other		0.7
	$	32.5

The increase in Taxes Other Than Income Taxes was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to our capital programs. The Connecticut Gross Earnings Tax increased primarily as a result of an increase in the transmission segment revenues and an increase in distribution segment revenues primarily related to retail transmission and higher transition cost recoveries in 2010, as compared to 2009. The increase in use taxes was due primarily to the absence in 2010 of a Connecticut state use tax refund.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	2010	2009	Increase/ (Decrease)	Percent
Interest on Long-Term Debt	$ 231.1	$ 224.7	$ 6.4	2.8 %
Interest on RRBs	20.6	36.5	(15.9)	(43.6)
Other Interest	(14.4)	12.4	(26.8)	(a)
	$ 237.3	$ 273.6	$ (36.3)	(13.3)%

(a) Percent greater than 100 percent not shown as it is not meaningful.

Interest Expense decreased in 2010, as compared to 2009, due primarily to the settlement of various state tax matters in the fourth quarter of 2010, which resulted in a reduction in Other Interest and lower Interest on RRBs resulting from lower principal balances outstanding, offset by higher Interest on Long-Term Debt as a result of $145 million in new long-term debt issuances in the first half of 2010 and $400 million in 2009, $150 million of which was issued by PSNH in December 2009.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	2010	2009	Increase	Percent
Other Income, Net	$ 41.9	$ 37.8	$ 4.1	10.8%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher AFUDC related to equity funds ($7 million), higher C&LM and EIA incentives ($3 million and $2 million, respectively), offset with lower investment and interest income ($4 million and $2 million, respectively).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	2010	2009	Increase	Percent
Income Tax Expense	$ 210.4	$ 179.9	$ 30.5	17.0%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to the impact of the 2010 Healthcare Act ($30 million) and higher pre-tax earnings ($10 million), partially offset by lower impacts related to flow-through items and other impacts ($5 million) and adjustments for prior years' taxes including return to provision adjustments ($5 million).

Selected Consolidated Sales Statistics	**2011**	**2010**	**2009**	**2008**	**2007**
Revenues: *(Thousands)*					
Regulated Companies:					
Residential	$ 2,091,270	$ 2,336,078	$ 2,569,278	$ 2,525,635	$ 2,558,547
Commercial	1,201,091	1,303,841	1,462,786	1,607,224	1,735,923
Industrial	252,878	268,598	297,854	399,753	412,381
Wholesale	350,413	506,475	445,261	545,127	392,675
Streetlighting and Railroads	35,283	42,387	33,035	38,522	45,880
Miscellaneous and Eliminations	47,485	(29,878)	128,118	24,673	84,043
Total Electric	3,978,420	4,427,501	4,936,332	5,140,934	5,229,449
Natural Gas	430,799	434,277	449,571	577,390	514,185
Total - Regulated Companies	4,409,219	4,861,778	5,385,903	5,718,324	5,743,634
Other and Eliminations	56,438	36,389	53,527	81,771	78,592
Total	$ 4,465,657	$ 4,898,167	$ 5,439,430	$ 5,800,095	$ 5,822,226
Regulated Companies - Sales: *(GWh)*					
Residential	14,766	14,913	14,412	14,509	15,051
Commercial	14,301	14,506	14,474	14,885	15,103
Industrial	4,418	4,481	4,423	5,149	5,635
Wholesale	1,020	3,423	4,183	3,576	3,855
Streetlighting and Railroads	327	330	336	340	353
Total	34,832	37,653	37,828	38,459	39,997
Regulated Companies - Customers: *(Average)*					
Residential	1,710,342	1,704,197	1,696,756	1,700,207	1,697,073
Commercial	193,505	192,266	189,265	190,067	189,727
Industrial	7,083	7,150	7,207	7,342	7,291
Streetlighting, Railroads and Wholesale*	5,735	6,292	7,548	4,605	3,855
Total Electric	1,916,665	1,909,905	1,900,776	1,902,221	1,897,946
Natural Gas	207,753	205,885	206,438	204,834	202,743
Total	2,124,418	2,115,790	2,107,214	2,107,055	2,100,689

*Customer counts were redefined with the implementation of a new customer service system (C2) completed in October 2008.

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RESULTS OF OPERATIONS   THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for CL&P included in this Annual Report on Form 10-K for the years December 31, 2011, 2010 and 2009:

<u>Comparison of 2011 to 2010</u>:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 2,548.4	$ 2,999.1	$ (450.7)	(15.0)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	929.9	1,253.3	(323.4)	(25.8)
Other Operating Expenses	570.5	524.3	46.2	8.8
Maintenance	149.0	96.5	52.5	54.4
Depreciation	157.7	172.2	(14.5)	(8.4)
Amortization of Regulatory Assets, Net	65.2	83.9	(18.7)	(22.3)
Amortization of Rate Reduction Bonds	-	167.0	(167.0)	(100.0)
Taxes Other Than Income Taxes	212.9	214.2	(1.3)	(0.6)
Total Operating Expenses	2,085.2	2,511.4	(426.2)	(17.0)
Operating Income	$ 463.2	$ 487.7	$ (24.5)	(5.0)%

Operating Revenues
CL&P's retail sales were as follows:

	For the Years Ended December 31,			
	2011	**2010**	**Decrease**	**Percent**
Retail Sales in GWh	22,315	22,666	(351)	(1.5)%

CL&P's Operating Revenues decreased in 2011, as compared to 2010, due primarily to:

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A $545.4 million decrease in distribution revenues related to the portions that are included in PURA approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked distribution revenues decreased due primarily to lower GSC and FMCC supply-related revenues ($316.4 million), lower CTA revenues ($165.5 million), lower wholesale revenues ($81.7 million) and lower retail other revenues ($38.4 million). The lower GSC and FMCC supply-related revenues were due primarily to lower customer rates resulting from lower average supply prices and additional customer migration to third party electric suppliers in 2011, as compared to 2010. These lower revenues were partially offset by higher FMCC delivery-related revenues ($28.6 million) and higher retail transmission revenues ($14 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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The portion of distribution revenues that impacts earnings increased $110.4 million in 2011, as compared to 2010, due primarily to the retail rate increase effective January 1, 2011.

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A $15.7 million decrease in transmission segment revenues was due primarily to a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year. This decrease was partially offset by increased transmission segment revenues due to a higher level of investment in the transmission infrastructure.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2011, as compared to 2010, due primarily to the following:

(Millions of Dollars)		**2011 Increase/(Decrease) as compared to 2010**
GSC Supply Costs	$	(325.8)
Deferred Fuel Costs		10.5
Other Purchased Power Costs		(60.4)
Other		52.3
	$	(323.4)

The decrease in GSC supply costs was due primarily to lower average supply prices and additional customer migration to third party electric suppliers in 2011, as compared to 2010. 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. These costs are included in PURA approved tracking mechanisms and do not impact earnings.

Other Operating Expenses

Other Operating Expenses increased in 2011, as compared to 2010, as a result of higher distribution segment expenses ($60.4 million) mainly as a result of the establishment of a $30 million storm fund reserve to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011, as a result of the October 2011 snowstorm and to provide contributions to certain Connecticut charitable organizations. In addition, there were higher administrative and general expenses, including higher pension costs. Partially offsetting these increases were lower transmission segment expenses ($7.4 million) and lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($4.3 million).

Maintenance

Maintenance increased in 2011, as compared to 2010, due primarily to the partial amortization in 2011 of the allowed regulatory deferral, which was recorded in maintenance expense in 2010, as a result of the June 30, 2010 rate case decision ($54.9 million).

Depreciation

Depreciation decreased in 2011, as compared to 2010, due primarily to a lower depreciation rate being used as a result of the 2010 distribution rate case decision that was effective July 1, 2010, partially offset by higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, decreased in 2011, as compared to 2010, due primarily to lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes ($38.2 million) and lower amortization of the SBC balance ($29.7 million). Partially offsetting these decreases were lower CTA transition costs ($197.6 million), partially offset by lower retail CTA revenue ($154.6 million), and the absence in 2011 of the impact from the 2010 Healthcare Act related to income taxes ($12 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs decreased in 2011, as compared to 2010, due to the maturity of RRBs in December 2010.

Taxes Other Than Income Taxes

The decrease in Taxes Other Than Income Taxes in 2011, as compared to 2010, was due primarily to a decrease in the Connecticut Gross Earnings Tax due primarily to lower transmission segment revenues and lower CTA revenues in 2011, as compared to 2010, partially offset by an increase in property taxes as a result of an increase in Property, Plant and Equipment related to CL&P s capital program and an increase in the tax rate.

Interest Expense

For the Years Ended December 31,

(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 131.9	$ 134.6	$ (2.7)	(2.0) %
Interest on RRBs	-	7.5	(7.5)	(100.0)
Other Interest	0.8	(4.4)	5.2	(a)
	$ 132.7	$ 137.7	$ (5.0)	(3.6) %

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

Interest Expense decreased in 2011, as compared to 2010, due primarily to the absence of Interest on RRBs in 2011, as CL&P's RRBs matured in December 2010, and lower Interest on Long-Term Debt in 2011 related to lower interest rates on the refinancing of the PCRBs. Partially offsetting these decreases was higher Other Interest in 2011, as compared to 2010, due to the prior year inclusion of a tax-related benefit.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**
Other Income, Net	$ 9.7	$ 26.7	$ (17.0)	(63.7)%

Other Income, Net decreased in 2011, as compared to 2010, due primarily to net losses on the NU supplemental benefit trust in 2011, compared to net gains in 2010, as well as the 2011 classification of C&LM and EIA incentives.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**
Income Tax Expense	$ 90.0	$ 132.4	$ (42.4)	(32.0)%

Income Tax Expense decreased in 2011, as compared to 2010, due primarily to the absence in 2011 of the impact from the 2010 Healthcare Act ($13.2 million), adjustments for prior years taxes including return to provision ($16.7 million), a decrease in pre-tax earnings ($7.3 million) and lower flow-through and other impacts ($5.2 million).

Comparison of 2010 to 2009:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 2,999.1	$ 3,424.5	$ (425.4)	(12.4)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	1,253.3	1,690.7	(437.4)	(25.9)
Other Operating Expenses	524.3	571.0	(46.7)	(8.2)
Maintenance	96.5	117.8	(21.3)	(18.1)
Depreciation	172.2	186.9	(14.7)	(7.9)
Amortization of Regulatory Assets, Net	83.9	45.8	38.1	83.2
Amortization of Rate Reduction Bonds	167.0	156.0	11.0	7.1
Taxes Other Than Income Taxes	214.2	191.2	23.0	12.0
Total Operating Expenses	2,511.4	2,959.4	(448.0)	(15.1)
Operating Income	$ 487.7	$ 465.1	$ 22.6	4.9 %

Operating Revenues

CL&P's retail sales were as follows:

	For the Years Ended December 31,			
	2010	**2009**	**Increase**	**Percent**
Retail Sales in GWh	22,666	22,266	400	1.8%

CL&P's Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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Lower distribution revenues related to the portions that are included in PURA approved tracking mechanisms that track and recover certain incurred costs that do not impact earnings. The tracked distribution revenues decreased due primarily to lower GSC and supply-related FMCC revenues ($421 million) and lower delivery-related FMCC revenues ($39 million). The lower GSC and supply-related FMCC revenues were due primarily to lower customer rates resulting from lower average supply prices and additional customer migration to third party electric suppliers in 2010, as compared to 2009. The lower delivery-related FMCC revenues were due primarily to changes in projections for certain delivery-related FMCC costs for 2010 that lowered the average rate charged to customers. These lower revenues were partially offset by higher retail transmission revenues ($37 million), higher transition cost recoveries ($27 million) and higher wholesale 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.

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The portion of distribution revenues that impacts earnings decreased $3 million due primarily to an unfavorable variance in demand and customer service charge components offset by a 1.8 percent increase in retail sales in 2010, as compared to 2009.

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Improved transmission segment revenues ($29 million) resulting from a higher level of investment in this segment and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to the following:

(Millions of Dollars)	**2010 Decrease as compared to 2009**	
GSC Supply Costs	$	(385.7)
Deferred Fuel Costs		(26.0)
Other Purchased Power Costs		(25.7)
	$	(437.4)

The decrease in GSC supply costs was due primarily to lower average supply prices and additional customer migration to third party electric suppliers in 2010, as compared to 2009. 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 decrease in deferred fuel costs was due primarily to a smaller net overrecovery in 2010, as compared to 2009. These costs are included in PURA approved tracking mechanisms and do not impact earnings.

Other Operating Expenses

Other Operating Expenses decreased in 2010, as compared to 2009, as a result of lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($69 million) including reliability must run ($32 million) and retail transmission ($31 million), partially offset by higher distribution segment expenses ($20 million) mainly as a result of higher administrative and general expenses, including higher pension costs, and higher transmission segment expenses ($3 million).

Maintenance

Maintenance decreased in 2010, as compared to 2009, primarily related to the allowed regulatory deferral of approximately $32 million as a result of the June 30, 2010 rate case decision, of which $29.5 million was recognized as a deferral in maintenance expense. Partially offsetting this decrease was higher distribution overhead line expenses ($3 million) and higher distribution segment vegetation management costs ($3 million).

Depreciation

Depreciation decreased in 2010, as compared to 2009, due primarily to a lower depreciation rate being used as a result of the distribution rate case decision that was effective July 1, 2010.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, increased in 2010, as compared to 2009, due primarily to higher retail CTA revenue ($22 million) and lower CTA transition costs ($17 million). Partially offsetting these increases was a deferral of lost tax benefits related to the 2010 Healthcare Act that we believe are probable of recovery in future distribution rates ($15 million).

Taxes Other Than Income Taxes

(Millions of Dollars)		**2010 Increase as compared to 2009**
Connecticut Gross Earnings Tax	$	9.8
Property Taxes		7.0
Use Taxes		5.9
Other		0.3
	$	23.0

The increase in Taxes Other Than Income Taxes was due primarily to an increase in the Connecticut Gross Earnings Tax as a result of the increase in the transmission segment revenues and an increase in distribution segment revenues primarily related to retail transmission and higher transition cost recoveries in 2010, as compared to 2009. The increase in property taxes was a result of an increase in Property, Plant and Equipment related to CL&P's capital programs. The increase in use taxes was due to the absence in 2010 of a Connecticut state use tax refund.

Interest Expense

	For the Years Ended December 31,						
(Millions of Dollars)		**2010**		**2009**		**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$	134.6	$	133.4	$	1.2	0.9 %

Interest on RRBs		7.5		19.1		(11.6)	(60.7)
Other Interest		(4.4)		3.3		(7.7)	(a)
	$	137.7	$	155.8	$	(18.1)	(11.6)%

(a) Percent greater than 100 percent not shown as it is not meaningful.

Interest Expense decreased in 2010, as compared to 2009, due primarily to lower Interest on RRBs resulting from lower principal balances outstanding and the settlement of various tax matters in the fourth quarter of 2010, which resulted in a reduction in Other Interest.

Other Income, Net

	For the Years Ended December 31,						
(Millions of Dollars)		**2010**		**2009**		**Increase**	**Percent**
Other Income, Net	$	26.7	$	25.9	$	0.8	3.1%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher C&LM and EIA incentives ($3 million and $3 million, respectively), offset with lower investment and interest income ($3 million) and lower AFUDC related to equity funds ($1 million).

Income Tax Expense

	For the Years Ended December 31,						
(Millions of Dollars)		**2010**		**2009**		**Increase**	**Percent**
Income Tax Expense	$	132.4	$	118.8	$	13.6	11.4%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to the impact of the 2010 Healthcare Act ($15 million) and higher pre-tax earnings ($5 million), partially offset by lower impacts related to flow-through items ($4 million) and adjustments to reconcile estimated taxes accrued to actual amounts reflected in our filed tax returns ($2 million).

LIQUIDITY

CL&P had cash flows provided by operating activities in 2011 of $513.3 million, compared with operating cash flows of $501.7 million in 2010 (2010 amount is net of RRB payments, which is included in financing activities). The improved cash flows in 2011 were due primarily to the impact of the DPUC (now PURA) July 1, 2010 distribution rate case decision, which increased CL&P s customer rates effective January 1, 2011, income tax refunds in 2011 of $27.5 million largely attributable to accelerated depreciation tax benefits, compared to income tax payments of $71.5 million in 2010. Offsetting these benefits was approximately $132 million of cash disbursements associated with Tropical Storm Irene and the October snowstorm.

CL&P had cash flows from operating activities in 2010 of $501.7 million, compared with operating cash flows of $482.2 million in 2009 (all amounts are net of RRB payments, which are included in financing activities). Improved cash flows in 2010 were attributed to a decrease in payments made related to CL&P's accounts payable in support of its operating activities. Improved cash flows were further due to increases in amortization on regulatory deferrals primarily attributable to 2009 activity within CL&P s CTA tracking mechanism where such costs exceeded revenues resulting in an unfavorable cash flow impact in 2009. Offsetting the improved cash flows was an increase in income tax payments of $29.1 million, which was the result of accelerated depreciation tax benefits received throughout 2009 not being extended for the full year of 2010 until the fourth quarter of 2010.

CL&P 2012 cash flows provided by operating activities are expected to be lower than in 2011 due primarily to approximately $27 million in bill credits provided to CL&P residential customers in February 2012. In 2012, cash payments for Tropical Storm Irene and the October storm costs are estimated to be approximately $140 million, as compared to 2011 payments of approximately $132 million.

On April 1, 2011, CL&P remarketed $62 million of tax-exempt secured PCRBs that were subject to mandatory tender. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.25 percent and have a mandatory tender on April 1, 2012, at which time CL&P expects to remarket the bonds.

On October 24, 2011, CL&P issued $120.5 million of PCRBs carrying a coupon of 4.375 percent that will mature on September 1, 2028, and $125 million of PCRBs carrying a coupon of 1.25 percent that mature on September 1, 2028 and are subject to mandatory tender on September 3, 2013. The proceeds of these issuances were used to refund $245.5 million of PCRBs that carried a coupon of 5.85 percent and had a maturity date of September 1, 2028. The refinancing is expected to reduce interest costs by approximately $7.5 million in 2012.

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 $424.9 million in 2011, compared with $380.3 million in 2010.

Investing activities in 2011 included Proceeds from Sale of Assets of $46.8 million included on the accompanying consolidated statement of cash flows related to the sale of certain CL&P transmission assets.

Financing activities in 2011 included $243.2 million in common dividends paid to NU parent, $31 million in short-term borrowings and $52.3 million in borrowings from the NU Money Pool.

Selected Consolidated Sales Statistics	**2011**	**2010**	**2009**	**2008**	**2007**
Revenues: *(Thousands)*					
Residential	$ 1,345,290	$ 1,597,754	$ 1,840,750	$ 1,811,845	$ 1,854,404
Commercial	732,968	821,872	935,586	1,042,077	1,182,196
Industrial	126,783	144,463	151,839	190,723	208,087
Wholesale	278,751	441,660	386,034	484,843	347,514
Streetlighting and Railroads	25,177	32,084	22,638	28,710	35,370
Miscellaneous	39,418	(38,731)	87,691	163	54,246
Total	$ 2,548,387	$ 2,999,102	$ 3,424,538	$ 3,558,361	$ 3,681,817
Sales: *(GWh)*					
Residential	10,093	10,196	9,848	9,913	10,336
Commercial	9,525	9,716	9,705	9,993	10,128
Industrial	2,414	2,467	2,427	2,945	3,264
Wholesale	1,591	3,040	3,434	3,637	3,563
Streetlighting and Railroads	284	286	286	294	304
Total	23,907	25,705	25,700	26,782	27,595
Customers: *(Average)*					
Residential	1,100,740	1,096,576	1,093,229	1,094,991	1,091,799
Commercial	103,975	103,166	101,814	102,464	102,411
Industrial	3,331	3,359	3,381	3,613	3,743
Streetlighting, Railroads and Wholesale*	4,260	4,366	5,307	2,883	2,583
Total	1,212,306	1,207,467	1,203,731	1,203,951	1,200,536

*Customers counts were redefined with the implementation of a new customer service system (C2) completed in October 2008.

RESULTS OF OPERATIONS PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for PSNH included in this Annual Report on Form 10-K for the years ended December 31, 2011, 2010 and 2009:

Comparison of 2011 to 2010:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 1,013.0	$ 1,033.4	$ (20.4)	(2.0)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	308.8	363.1	(54.3)	(15.0)
Other Operating Expenses	217.1	230.2	(13.1)	(5.7)
Maintenance	93.1	82.4	10.7	13.0
Depreciation	76.1	67.2	8.9	13.2
Amortization of Regulatory Assets, Net	25.4	11.2	14.2	(a)
Amortization of Rate Reduction Bonds	53.4	50.4	3.0	6.0
Taxes Other Than Income Taxes	59.0	52.7	6.3	12.0
Total Operating Expenses	832.9	857.2	(24.3)	(2.8)
Operating Income	$ 180.1	$ 176.2	$ 3.9	2.2 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

PSNH's retail sales were as follows:

	For the Years Ended December 31,			
	2011	**2010**	**Decrease**	**Percent**
Retail Sales in GWh	7,815	7,847	(32)	(0.4)%

PSNH's Operating Revenues decreased in 2011, as compared to 2010, due primarily to:

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A $46.4 million decrease in distribution revenues related to the portions that are included in NHPUC approved tracking mechanisms that recover certain incurred costs and do not impact earnings. This decrease primarily related to lower purchased fuel and power costs ($33.7 million), mostly related to lower energy prices and a slight increase in ES customer migration to third party electric suppliers. In addition, there were lower stranded cost recoveries ($5.3 million) and lower retail transmission revenues ($2.8 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers and undercollections to be recovered from customers in future periods.

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The portion of distribution revenues that impacts earnings increased $19.1 million in 2011, as compared to 2010, due primarily to the retail rate increase effective July 1, 2010.

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A $6.9 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2011, as compared to 2010, due primarily to lower energy prices and a slight increase in ES customer migration to third party electric suppliers and lower retail sales for PSNH's remaining ES customers.

Other Operating Expenses

Other Operating Expenses decreased in 2011, as compared to 2010, as a result of lower retail transmission expenses ($8.7 million) and lower general and administrative costs ($3.9 million).

Maintenance

Maintenance increased in 2011, as compared to 2010, due primarily to higher boiler equipment and maintenance costs at the generation business related to the absence in 2011 of insurance proceeds received in 2010 related to turbine damage, which reduced 2010 costs ($7.4 million) and higher distribution segment routine overhead line expenses ($5.7 million) primarily related to storm costs that did not meet the minimum requirement for regulatory deferral, offset by lower distribution segment vegetation management costs ($1.9 million).

Depreciation

Depreciation increased in 2011, as compared to 2010, due primarily to a higher depreciation rate being used as a result of the distribution rate case decision that was effective July 1, 2010 and higher utility plant balances resulting from completed construction projects placed into service related to PSNH's capital programs.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net increased in 2011, as compared to 2010, due primarily to increases in ES amortization ($11.4 million), the absence in 2011 of the impact from the 2010 Healthcare Act related to income taxes ($6.7 million) and TCAM amortization ($5.9 million), partially offset by a decrease in SCRC amortization ($7.4 million).

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes in 2011, as compared to 2010, was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to PSNH s capital program and an increase in the tax rate**.**

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 36.8	$ 36.2	$ 0.6	1.7 %
Interest on RRBs	6.3	9.7	(3.4)	(35.1)
Other Interest	1.0	1.2	(0.2)	(16.7)
	$ 44.1	$ 47.1	$ (3.0)	(6.4)%

Interest Expense decreased in 2011, as compared to 2010, due primarily to lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase**	**Percent**
Other Income, Net	$ 14.3	$ 11.7	$ 2.6	22.2%

Other Income, Net increased in 2011, as compared to 2010, due primarily to higher AFUDC related to equity funds related to PSNH s Clean Air Project, partially offset by net losses on the NU supplemental benefit trust in 2011, compared to net gains in 2010.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**
Income Tax Expense	$ 49.9	$ 50.8	$ (0.9)	(1.8)%

Income Tax Expense decreased in 2011, as compared to 2010, due primarily to the absence of the impact from the 2010 Healthcare Act ($6.1 million); partially offset by an increase in pre-tax earnings ($5.6 million).

Comparison of 2010 to 2009:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	2010	2009	Increase/ (Decrease)	Percent
Operating Revenues	$ 1,033.4	$ 1,109.6	$ (76.2)	(6.9)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	363.1	520.5	(157.4)	(30.2)
Other Operating Expenses	230.2	239.7	(9.5)	(4.0)
Maintenance	82.4	87.0	(4.6)	(5.3)
Depreciation	67.2	62.0	5.2	8.4
Amortization of Regulatory Assets/(Liabilities), Net	11.2	(29.6)	40.8	(a)
Amortization of Rate Reduction Bonds	50.4	47.5	2.9	6.1
Taxes Other Than Income Taxes	52.7	47.9	4.8	10.0
Total Operating Expenses	857.2	975.0	(117.8)	(12.1)
Operating Income	$ 176.2	$ 134.6	$ 41.6	30.9 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

PSNH's retail sales were as follows:

	For the Years Ended December 31,			
	2010	2009	Increase	Percent
Retail Sales in GWh	7,847	7,750	97	1.3%

PSNH's Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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A $125 million decrease in distribution revenues that did not impact earnings. Of this decrease, $121 million related to lower recovery of purchased fuel and power costs mostly related to ES customer migration to third party electric suppliers, $19 million in lower transmission segment intracompany billings to the distribution segment that are eliminated in consolidation and $11 million related to lower wholesale revenues, offset by higher retail transmission revenues ($25 million) and an increase in the SCRC ($12 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers and undercollections to be recovered from customers in future periods.

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A $40 million increase in distribution segment revenues that impacts earnings primarily as a result of the retail rate increase effective July 1, 2010 and higher sales volume. Retail sales increased 1.3 percent in 2010 compared to 2009.

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A $9 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to an increased level of ES customer migration to third party electric suppliers, partially offset by higher retail sales.

Other Operating Expenses

Other Operating Expenses decreased in 2010, as compared to 2009, due primarily to lower distribution segment expenses ($7 million), mainly as a result of the rate case decision changing the collection of certain expenses to be tracked through the TCAM included in Amortization of Regulatory Assets/(Liabilities), Net in 2010.

Maintenance

Maintenance decreased in 2010, as compared to 2009, due primarily to lower boiler equipment and maintenance costs at the generation business ($12 million) as a result of insurance proceeds received in 2010 related to turbine damage, offset by higher distribution overhead line expenses related to storms in 2010 ($8 million).

Depreciation

Depreciation increased in 2010, as compared to 2009, due primarily to higher utility plant balances resulting from completed construction projects placed into service related to PSNH s capital programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net increased in 2010, as compared to 2009, due primarily to increases in ES deferral ($42 million) and TCAM ($11 million) offset by decreases in the impact of the 2010 Healthcare Act related to the deferral of lost tax benefits that we believe are probable of recovery in future distribution rates ($7 million) and the Northern Wood Power Project accrual ($5 million).

Taxes Other Than Income Taxes

(Millions of Dollars)	2010 Increase as compared to 2009
Property Taxes	$ 3.1
Use Taxes	1.5
Other	0.2
	$ 4.8

The increase in Taxes Other Than Income Taxes was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to PSNH's capital programs.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	2010	2009	Increase/ (Decrease)	Percent
Interest on Long-Term Debt	$ 36.2	$ 33.0	$ 3.2	9.7 %
Interest on RRBs	9.7	13.1	(3.4)	(26.0)
Other Interest	1.2	0.4	0.8	(a)
	$ 47.1	$ 46.5	$ 0.6	1.3 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Interest Expense increased in 2010, as compared to 2009, due primarily to higher Interest on Long-Term Debt resulting from the $150 million debt issuance in December 2009, offset by lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	2010	2009	Increase	Percent
Other Income, Net	$ 11.7	$ 9.5	$ 2.2	23.2%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher AFUDC related to equity funds ($7 million), offset by higher rental expenses ($3 million) and lower interest income ($1 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	2010	2009	Increase	Percent
Income Tax Expense	$ 50.8	$ 32.0	$ 18.8	58.8%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to higher pre-tax earnings ($13 million) and the impact of the 2010 Healthcare Act ($7 million), partially offset by lower impact related to flow-through items ($2 million).

LIQUIDITY

PSNH had cash flows provided by operating activities in 2011 of $151.8 million, compared with operating cash flows of $145.4 million in 2010 and $58.2 million in 2009 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows were due primarily to income tax refunds in 2011 of $29.3 million largely attributable to accelerated depreciation tax benefits, compared to income tax payments of $1.6 million in 2010, and the impact of PSNH s 2010 distribution rate case settlement, which increased PSNH rates effective July 1, 2010. Offsetting these benefits was a contribution into the NU Pension Plan of $112.6 million in 2011, compared with a contribution into the NU Pension Plan of $45 million in 2010.

Selected Consolidated Sales Statistics	**2011**	**2010**	**2009**	**2008**	**2007**
Revenues: *(Thousands)*					
Residential	$ 532,813	$ 529,992	$ 506,725	$ 472,486	$ 457,616
Commercial	340,597	360,373	407,743	431,461	413,196
Industrial	85,845	90,243	112,460	169,785	156,258
Wholesale	27,198	33,003	41,193	35,935	25,030
Streetlighting	6,218	6,669	6,331	6,515	6,018
Miscellaneous	20,332	13,159	35,139	25,020	24,954
Total	$ 1,013,003	$ 1,033,439	$ 1,109,591	$ 1,141,202	$ 1,083,072
Sales: *(GWh)*					
Residential	3,141	3,175	3,097	3,105	3,176
Commercial	3,315	3,309	3,311	3,361	3,403
Industrial	1,336	1,339	1,318	1,435	1,528
Wholesale	(703)	206	562	(243)	105
Streetlighting	23	24	24	25	24
Total	7,112	8,053	8,312	7,683	8,236
Customers: *(Average)*					
Residential	422,072	420,481	417,670	418,107	417,420
Commercial	72,021	71,746	70,984	70,807	70,341
Industrial	3,049	3,088	3,134	2,978	2,770
Streetlighting and Wholesale*	1,074	1,442	1,438	970	602
Total	498,216	496,757	493,226	492,862	491,133

*Customers counts were redefined with the implementation of a new customer service system (C2) completed in October 2008.

RESULTS OF OPERATIONS WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for WMECO included in this Annual Report on Form 10-K for the years ended December 31, 2011, 2010 and 2009:

Comparison of 2011 to 2010:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 417.3	$ 395.2	$ 22.1	5.6 %
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	145.6	157.3	(11.7)	(7.4)
Other Operating Expenses	98.3	102.1	(3.8)	(3.7)
Maintenance	17.7	19.2	(1.5)	(7.8)
Depreciation	26.5	23.6	2.9	12.3
Amortization of Regulatory Assets, Net	6.4	2.3	4.1	(a)
Amortization of Rate Reduction Bonds	16.5	15.5	1.0	6.5
Taxes Other Than Income Taxes	17.9	16.5	1.4	8.5
Total Operating Expenses	328.9	336.5	(7.6)	(2.3)
Operating Income	$ 88.4	$ 58.7	$ 29.7	50.6 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

WMECO's retail sales were as follows:

	For the Years Ended December 31,			
	2011	**2010**	**Decrease**	**Percent**
Retail Sales in GWh	3,695	3,732	(37)	(1.0)%

WMECO's Operating Revenues increased in 2011, as compared to 2010, due primarily to:

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An $18.6 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

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The portion of distribution revenues that impacts earnings increased $6.1 million due primarily to the retail rate increase effective February 1, 2011 ($11.1 million), partially offset by the establishment of a reserve related to a wholesale billing adjustment made in the third quarter of 2011 ($5 million).

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Amounts related to distribution revenues that did not impact earnings and are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs decreased by $2.5 million in 2011, compared to 2010. Included in these amounts are pension, C&LM collections and other trackers. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections to be recovered from customers in future periods.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2011, as compared to 2010, due primarily to lower basic service supply costs in addition to an increase in the deferral of excess basic service expense over basic service revenue. The basic service supply costs are the contractual amounts WMECO must pay to various suppliers that serve this load after winning a competitive solicitation process. To the extent these costs do not match revenues collected from customers, the DPU allows the difference to be deferred for future recovery from or refund to customers. The basic service supply costs decreased due primarily to lower supplier contract rates, partially offset by increased load volumes.

Other Operating Expenses

Other Operating Expenses decreased in 2011, as compared to 2010, as a result of a decrease in bad debt expense ($7.2 million) and lower retail transmission expenses ($2.4 million), offset by a reduction in the amount of deferred C&LM costs ($3.1 million) and an increase in administrative and general expenses ($0.8 million), primarily related to higher pension costs. All these costs are recovered through distribution tracking mechanisms and have no earnings impact.

Maintenance

Maintenance decreased in 2011, as compared to 2010, due primarily to lower distribution segment routine overhead line expenses ($2.5 million), partially offset by higher transmission segment routine overhead line expenses ($0.8 million).

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Depreciation

Depreciation increased in 2011, as compared to 2010, due primarily to a higher depreciation rate being used at WMECO as a result of the distribution rate case decision that was effective February 1, 2011 and higher utility plant balances resulting from completed construction projects placed into service related to WMECO's capital programs.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, increased in 2011, as compared to 2010, due primarily to the absence in 2011 of the impact from the 2010 Healthcare Act related to income taxes ($4 million), the amortization of the 2008 through 2010 major storm costs ($3.1 million) and the amortization related to the recovery of certain hardship customer receivables ($1 million). The recovery of the storm costs and hardship customer receivables were approved by the DPU as result of WMECO's rate case decision effective February 1, 2011. Partially offsetting these increases was a decrease in transition charge amortization ($3.5 million).

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes in 2011, as compared to 2010, was due primarily to an increase in property taxes related to an increase in Property, Plant and Equipment related to WMECO s capital program and an increase in the tax rate**.**

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 20.0	$ 18.0	$ 2.0	11.1 %
Interest on RRBs	2.3	3.4	(1.1)	(32.4)
Other Interest	1.3	0.4	0.9	(a)
	$ 23.6	$ 21.8	$ 1.8	8.3 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Interest Expense increased in 2011, as compared to 2010, due primarily to higher Interest on Long-Term Debt resulting from the $100 million debt issuance in September 2011, offset by lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**
Other Income, Net	$ 1.5	$ 2.6	$ (1.1)	(42.3)%

Other Income, Net decreased in 2011, as compared to 2010, due primarily to net losses on the NU supplemental benefit trust in 2011, compared to net gains in 2010.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**Increase**	**Percent**
Income Tax Expense	$ 23.2	$ 16.3	$ 6.9	42.3%

Income Tax Expense increased in 2011, as compared to 2010, due primarily to an increase in pre-tax earnings ($10.4 million); partially offset by the absence in 2011 of the impact from the 2010 Healthcare Act ($2.5 million).

Comparison of 2010 to 2009:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 395.2	$ 402.4	$ (7.2)	(1.8)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	157.3	192.2	(34.9)	(18.2)
Other Operating Expenses	102.1	85.6	16.5	19.3
Maintenance	19.2	17.9	1.3	7.3
Depreciation	23.6	22.5	1.1	4.9
Amortization of Regulatory Assets/(Liabilities), Net	2.3	(3.0)	5.3	(a)
Amortization of Rate Reduction Bonds	15.5	14.5	1.0	6.9
Taxes Other Than Income Taxes	16.5	14.1	2.4	17.0
Total Operating Expenses	336.5	343.8	(7.3)	(2.1)
Operating Income	$ 58.7	$ 58.6	$ 0.1	0.2 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

WMECO's retail sales were as follows:

	For the Years Ended December 31,			
	2010	**2009**	**Increase**	**Percent**
Retail Sales in GWh	3,732	3,644	88	2.4%

WMECO's Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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A $20 million decrease related to distribution revenues that did not impact earnings and was included in DPU approved tracking mechanisms that track the recovery of certain incurred costs through WMECO's tariffs. Included in these amounts are a decrease of $31 million related to a lower recovery of energy supply costs and a decrease of $7 million related to transmission segment intracompany billings to the distribution segment that are eliminated in consolidation. Offsetting these decreases were increases in transition cost recoveries, C&LM collections and retail transmission revenues ($8 million, $5 million and $4 million, respectively). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections to be recovered from customers in future periods.

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The portion of distribution revenues that impacts earnings increased $2 million due primarily to a 2.4 percent increase in retail sales in 2010, as compared to 2009.

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A $10 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to lower basic service supply costs. The basic service supply costs are the contractual amounts WMECO must pay to various suppliers that serve this load after winning a competitive solicitation process. These costs decreased due primarily to lower supplier contract rates.

Other Operating Expenses

Other Operating Expenses increased in 2010, as compared to 2009, as a result of higher distribution segment expenses ($9 million) resulting from higher administrative and general expenses, including pension costs, higher costs that are recovered through distribution tracking mechanisms and have no earnings impact primarily related to an increase in C&LM expenses attributable to the Massachusetts Green Communities Act ($6 million), and higher transmission segment expenses ($1 million).

Maintenance

Maintenance increased in 2010, as compared to 2009, due primarily to higher distribution overhead line expenses.

Depreciation

Depreciation increased in 2010, as compared to 2009, due primarily to higher utility plant balances resulting from completed construction projects placed into service related to WMECO's capital programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net increased in 2010, as compared to 2009, due primarily to the recovery of the previously deferred unrecovered stranded generation costs ($11 million), offset by a deferral of lost tax benefits related to the 2010 Healthcare Act that we believe are probable of recovery in future distribution rates ($4 million).

Taxes Other Than Income Taxes

(Millions of Dollars)	**2010 Increase as compared to 2009**
Property Taxes	$ 1.5
Use Taxes	0.6
Other	0.3
	$ 2.4

The increase in Taxes Other Than Income Taxes was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to WMECO's capital programs.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 18.0	$ 14.1	$ 3.9	27.7 %
Interest on RRBs	3.4	4.3	(0.9)	(20.9)
Other Interest	0.4	0.9	(0.5)	(55.6)
	$ 21.8	$ 19.3	$ 2.5	13.0 %

Interest Expense increased in 2010, as compared to 2009, due primarily to higher Interest on Long-Term Debt resulting from the $95 million debt issuance in March 2010, offset by lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase**	**Percent**
Other Income, Net	$ 2.6	$ 1.8	$ 0.8	44.4%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher AFUDC related to equity funds ($1 million) and higher interest income ($1 million), offset by lower investment income ($1 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase**	**Percent**
Income Tax Expense	$ 16.3	$ 14.9	$ 1.4	9.4%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to the impact of the 2010 Healthcare Act ($3 million), partially offset by lower pre-tax earnings and other impacts ($2 million).

LIQUIDITY

WMECO had cash flows provided by operating activities in 2011 of $108 million, compared with operating cash flows of $50.5 million in 2010 and $47.7 million in 2009 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows were due primarily to the impact of the DPU distribution rate case decision that was effective February 1, 2011, income tax refunds in 2011 of $4.9 million largely attributable to accelerated depreciation tax benefits, compared to income tax payments of $5 million in 2010 and a net positive cash flow impact associated with transmission overrecoveries in 2011, as compared to 2010. Offsetting these benefits was approximately $15 million of cash disbursements associated with Tropical Storm Irene and the October snowstorm.

Selected Consolidated Sales Statistics

	2011	2010	2009	2008	2007
Revenues: *(Thousands)*					
Residential	$ 213,167	$ 208,332	$ 221,803	$ 241,303	$ 246,526
Commercial	127,526	121,597	119,457	133,686	140,531
Industrial	40,250	33,892	33,555	39,245	48,036
Wholesale	44,464	31,812	18,034	24,349	20,131
Streetlighting	3,888	3,633	4,066	3,297	4,492
Miscellaneous	(11,980)	(4,105)	5,498	(353)	5,029
Total	$ 417,315	$ 395,161	$ 402,413	$ 441,527	$ 464,745
Sales: *(GWh)*					
Residential	1,533	1,542	1,467	1,491	1,539
Commercial	1,474	1,496	1,474	1,547	1,589
Industrial	669	675	679	769	842
Wholesale	131	177	187	179	178
Streetlighting	19	20	24	22	25
Total	3,826	3,910	3,831	4,008	4,173
Customers: *(Average)*					
Residential	187,529	187,140	185,856	187,109	187,854
Commercial	17,630	17,475	16,587	16,916	17,096
Industrial	702	703	692	751	777
Streetlighting and Wholesale	434	516	835	785	703
Total	206,295	205,834	203,970	205,561	206,430

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. The remaining unregulated wholesale portfolio held by Select Energy includes contracts that are market risk-sensitive, including a wholesale energy sales contract through 2013 with an agency comprised of municipalities with approximately 0.1 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 also exposed to market price volatility.

As Select Energy's contract volumes are winding down, and as the wholesale energy sales contract is substantially hedged against price risks, we have limited exposure to commodity price risks. We have not entered into any energy contracts 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. 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. A hypothetical 30 percent increase or decrease in forward energy, ancillary or capacity prices would not have a material impact on earnings.

The impact of a change in electricity prices on wholesale derivative transactions as of December 31, 2011 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.

Other Risk Management Activities

We have implemented an Enterprise Risk Management methodology for identifying the principal risks of the Company. Enterprise Risk Management 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. Our management analyzes risks to determine materiality and other attributes such as likelihood and impact, velocity, and mitigation strategies. Management broadly considers our business model, the utility industry, the global economy and the current environment to identify risks.

However, there can be no assurances that the Enterprise Risk Management process will identify or manage every risk or event that could impact our financial position, results of operations or cash flows. The findings of this process are periodically discussed with our Board of Trustees.

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, 2011, approximately 93 percent 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. In addition, as of December 31, 2011, we maintained a fixed-to-floating interest rate swap at NU parent associated with $263 million of its fixed-rate debt due on April 1, 2012.

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.

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 monitor contracting risks, including credit risk. As of December 31, 2011, our Regulated companies neither held cash collateral nor deposited cash 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. For further information, see Note 12D, Commitments and Contingencies - Guarantees and Indemnifications, to the consolidated financial statements.

Select Energy has also established written credit policies with regard to its counterparties to minimize overall credit risk on all types of transactions. These policies require collateral 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.

If the respective unsecured debt ratings of NU parent or PSNH were reduced to below investment grade by either Moody s or S&P, certain of NU s and PSNH s contracts would require additional collateral in the form of cash or LOCs to be provided to counterparties and independent system operators. If such an event occurred as of December 31, 2011, NU and PSNH would have been required to provide additional cash or LOCs in an aggregate amount of $24.3 million and $4 million, respectively. NU and PSNH would have been and remain able to provide that collateral.

For further information on cash collateral deposited and posted with counterparties as well as any cash collateral netted against the fair value of the related derivative contracts, see Note 4, Derivative Instruments, to the consolidated financial statements.

Item 8.

Financial Statements and Supplementary Data

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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, 2011.

February 24, 2012

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 of Northeast Utilities and subsidiaries (the Company) as of December 31, 2011 and 2010 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, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15 of Part IV. We also have audited the Company's internal control over financial reporting as of December 31, 2011 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, 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 Northeast Utilities and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 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, 2011, 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

Hartford, Connecticut

February 24, 2012

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2011	2010
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 6,559	$ 23,395
Receivables, Net	488,002	523,644
Unbilled Revenues	175,207	208,834
Taxes Receivable	4,931	89,638
Fuel, Materials and Supplies	248,958	244,043
Regulatory Assets	255,144	238,699
Marketable Securities	70,970	78,306
Prepayments and Other Current Assets	107,701	100,441
Total Current Assets	1,357,472	1,507,000
Property, Plant and Equipment, Net	10,403,065	9,567,726
Deferred Debits and Other Assets:		
Regulatory Assets	3,267,710	2,756,580
Goodwill	287,591	287,591
Marketable Securities	60,311	51,201
Derivative Assets	98,357	123,242
Other Long-Term Assets	172,560	179,261
Total Deferred Debits and Other Assets	3,886,529	3,397,875
Total Assets	$ 15,647,066	$ 14,472,601

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2011	2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 317,000	$ 267,000
Long-Term Debt - Current Portion	331,582	66,286
Accounts Payable	633,282	417,285
Obligations to Third Party Suppliers	75,068	74,659
Accrued Taxes	69,592	107,067
Accrued Interest	69,198	74,740
Regulatory Liabilities	167,844	99,403
Derivative Liabilities	107,558	71,501
Other Current Liabilities	176,558	167,206
Total Current Liabilities	1,947,682	1,345,147
Rate Reduction Bonds	112,260	181,572
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,868,316	1,636,750
Regulatory Liabilities	266,145	339,655
Derivative Liabilities	959,876	909,668
Accrued Pension, SERP and PBOP	1,326,037	1,050,614
Other Long-Term Liabilities	420,011	447,496
Total Deferred Credits and Other Liabilities	4,840,385	4,384,183
Capitalization:		
Long-Term Debt	4,614,913	4,632,866
Noncontrolling Interest in Consolidated Subsidiary:		
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Equity:		
Common Shareholders' Equity:		
Common Shares	980,264	978,909
Capital Surplus, Paid In	1,797,884	1,777,592
Retained Earnings	1,651,875	1,452,777
Accumulated Other Comprehensive Loss	(70,686)	(43,370)
Treasury Stock	(346,667)	(354,732)
Common Shareholders' Equity	4,012,670	3,811,176
Noncontrolling Interests	2,956	1,457
Total Equity	4,015,626	3,812,633
Total Capitalization	8,746,739	8,561,699

Commitments and Contingencies (Note 12)				
Total Liabilities and Capitalization	$	15,647,066	$	14,472,601

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars, Except Share Information)	2011	2010	2009
Operating Revenues	$ 4,465,657	$ 4,898,167	$ 5,439,430
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	1,580,683	1,985,634	2,629,619
Other Operating Expenses	1,026,192	958,417	1,001,190
Maintenance	271,779	210,283	234,173
Depreciation	302,192	300,737	309,618
Amortization of Regulatory Assets, Net	97,113	95,593	13,315
Amortization of Rate Reduction Bonds	69,912	232,871	217,941
Taxes Other Than Income Taxes	323,610	314,741	282,199
Total Operating Expenses	3,671,481	4,098,276	4,688,055
Operating Income	794,176	799,891	751,375
Interest Expense:			
Interest on Long-Term Debt	231,630	231,089	224,712
Interest on Rate Reduction Bonds	8,611	20,573	36,524
Other Interest	10,184	(14,371)	12,401
Interest Expense	250,425	237,291	273,637
Other Income, Net	27,715	41,916	37,801
Income Before Income Tax Expense	571,466	604,516	515,539
Income Tax Expense	170,953	210,409	179,947
Net Income	400,513	394,107	335,592
Net Income Attributable to Noncontrolling Interests	5,820	6,158	5,559
Net Income Attributable to Controlling Interests	$ 394,693	$ 387,949	$ 330,033
Basic Earnings Per Common Share	$ 2.22	$ 2.20	$ 1.91
Diluted Earnings Per Common Share	$ 2.22	$ 2.19	$ 1.91
Weighted Average Common Shares Outstanding:			
Basic	177,410,167	176,636,086	172,567,928
Diluted	177,804,568	176,885,387	172,717,246

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, 2011	2010	2009
Net Income	$ 400,513	$ 394,107	$ 335,592
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	(14,177)	200	200
Changes in Unrealized Gains/(Losses) on Other Securities	506	402	(976)
Change in Funded Status of Pension, SERP and PBOP Benefit Plans	(13,645)	(505)	(5,426)
Other Comprehensive Income/(Loss), Net of Tax	(27,316)	97	(6,202)
Comprehensive Income Attributable to Noncontrolling Interests	(5,820)	(6,158)	(5,559)
Comprehensive Income Attributable to Controlling Interests	$ 367,377	$ 388,046	$ 323,831

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(Thousands of Dollars, Except Share Information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Deferred Contribution Plan	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Common Shareholders' Equity
Balance as of January 1, 2009	155,834,361	$ 881,061	$ 1,475,006	$ (15,481)	$ 1,078,594	$ (37,265)	$ (361,603)	$ 3,020,312
Adoption of Accounting Guidance for Other-Than-Temporary Impairments					728	(728)		-
Net Income					335,592			335,592
Dividends on Common Shares - $0.95 Per Share					(162,812)			(162,812)
Issuance of Common Shares, $5 Par Value	19,242,939	96,215	293,502					389,717
Dividends on Preferred Stock					(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	175,620,024	977,276	1,762,097	(2,944)	1,246,543	(43,467)	(361,603)	3,577,902
Net Income					394,107			394,107

Dividends on Common Shares - $1.025 Per Share					(181,715)			(181,715)
Issuance of Common Shares, $5 Par Value	326,526	1,633	5,745					7,378
Dividends on Preferred Stock					(6,101)			(6,101)
Net Income Attributable to Noncontrolling Interests					(57)			(57)
Allocation of Benefits - ESOP	127,054		439	2,944				3,383
ESOP Benefits from Treasury Shares			3,856				(3,856)	-
Change in Restricted Shares, Net			4,868					4,868
Change in Treasury Stock	374,477						10,727	10,727
Tax Deduction for Stock Options Exercised and Employee Stock Purchase Plan Disqualifying Dispositions			866					866
Capital Stock Expenses, Net			(279)					(279)
Other Comprehensive Income						97		97
Balance as of December 31, 2010	176,448,081	978,909	1,777,592	-	1,452,777	(43,370)	(354,732)	3,811,176
Net Income					400,513			400,513
Dividends on Common Shares - $1.10 Per Share					(195,595)			(195,595)
Issuance of Common Shares, $5 Par Value	271,030	1,355	4,496					5,851
Dividends on Preferred Stock					(5,559)			(5,559)
Net Income Attributable to Noncontrolling Interests					(261)			(261)
ESOP Benefits from Treasury			7,048				(7,048)	-

Shares								
Change in Restricted Shares, Net			7,359					7,359
Change in Treasury Stock	439,581						15,113	15,113
Tax Deduction for Stock Options Exercised and Employee Stock Purchase Plan Disqualifying Dispositions			1,338					1,338
Capital Stock Expenses, Net			51					51
Other Comprehensive Loss						(27,316)		(27,316)
Balance as of December 31, 2011	177,158,692	$ 980,264	$ 1,797,884	$ -	$ 1,651,875	$ (70,686)	$ (346,667)	$ 4,012,670

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

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NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2011	2010	2009
Operating Activities:			
Net Income	$ 400,513	$ 394,107	$ 335,592
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	16,420	31,352	53,947
Depreciation	302,192	300,737	309,618
Deferred Income Taxes	196,761	210,939	125,890
Pension and PBOP Expense	133,000	103,861	58,732
Pension and PBOP Contributions	(191,101)	(90,633)	(37,160)
Regulatory (Under)/Over Recoveries, Net	(76,896)	20,750	37,868
Amortization of Regulatory Assets, Net	97,113	95,593	13,315
Amortization of Rate Reduction Bonds	69,912	232,871	217,941
Derivative Assets and Liabilities	(35,441)	(11,812)	(18,798)
Other	(29,751)	(72,151)	(26,003)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	17,570	(51,285)	91,081
Fuel, Materials and Supplies	(11,033)	38,126	25,957
Taxes Receivable/Accrued	49,642	(82,103)	16,194
Accounts Payable	18,916	(44,355)	(208,180)
Other Current Assets and Liabilities	12,569	17,466	(6,876)
Net Cash Flows Provided by Operating Activities	970,386	1,093,463	989,118
Investing Activities:			
Investments in Property, Plant and Equipment	(1,076,730)	(954,472)	(908,146)
Proceeds from Sales of Marketable Securities	149,441	174,865	208,947
Purchases of Marketable Securities	(151,972)	(177,204)	(211,243)
Proceeds from Sale of Assets	46,841	-	-
Other Investing Activities	13,833	(1,157)	7,963
Net Cash Flows Used in Investing Activities	(1,018,587)	(957,968)	(902,479)
Financing Activities:			
Issuance of Common Shares	-	-	383,295
Cash Dividends on Common Shares	(194,555)	(180,542)	(162,381)
Cash Dividends on Preferred Stock	(5,559)	(5,559)	(5,559)
Increase/(Decrease) in Short-Term Debt	50,000	166,687	(518,584)

Issuance of Long-Term Debt	627,500	145,000	462,000
Retirements of Long-Term Debt	(369,586)	(4,286)	(54,286)
Retirements of Rate Reduction Bonds	(69,312)	(260,864)	(244,075)
Other Financing Activities	(7,123)	512	(9,913)
Net Cash Flows Provided by/(Used in) Financing Activities	31,365	(139,052)	(149,503)
Net Decrease in Cash and Cash Equivalents	(16,836)	(3,557)	(62,864)
Cash and Cash Equivalents - Beginning of Year	23,395	26,952	89,816
Cash and Cash Equivalents - End of Year	$ 6,559	$ 23,395	$ 26,952

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, 2011.

February 24, 2012

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, 2011 and 2010 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, 2011 . Our audits also included the financial statement schedules listed in the Index at Item 15 of Part IV. We also have audited the Company's internal control over financial reporting as of December 31, 2011 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, 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 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, 2011, 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

Hartford, Connecticut

February 24, 2012

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)		As of December 31, 2011		2010
ASSETS				
Current Assets:				
Cash	$	1	$	9,762
Receivables, Net		295,028		317,530
Accounts Receivable from Affiliated Companies		1,548		822
Unbilled Revenues		94,995		116,392
Taxes Receivable		6,988		48,360
Regulatory Assets		170,197		157,530
Materials and Supplies		61,102		63,811
Prepayments and Other Current Assets		46,932		27,466
Total Current Assets		676,791		741,673
Property, Plant and Equipment, Net		5,827,384		5,586,504
Deferred Debits and Other Assets:				
Regulatory Assets		2,103,830		1,721,416
Derivative Assets		93,755		115,870
Other Long-Term Assets		89,636		89,729
Total Deferred Debits and Other Assets		2,287,221		1,927,015
Total Assets	$	8,791,396	$	8,255,192

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

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THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2011	2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 31,000	$ -
Notes Payable to Affiliated Companies	58,525	6,225
Long-Term Debt - Current Portion	62,000	62,000
Accounts Payable	340,321	204,868
Accounts Payable to Affiliated Companies	53,439	53,207
Obligations to Third Party Suppliers	67,967	68,692
Accrued Taxes	59,046	92,061
Accrued Interest	35,279	42,548
Regulatory Liabilities	108,291	75,716
Derivative Liabilities	95,881	46,781
Other Current Liabilities	66,786	46,209
Total Current Liabilities	978,535	698,307
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,215,989	1,068,344
Regulatory Liabilities	139,307	206,394
Derivative Liabilities	935,849	883,091
Accrued Pension, SERP and PBOP	260,571	127,116
Other Long-Term Liabilities	215,640	237,163
Total Deferred Credits and Other Liabilities	2,767,356	2,522,108
Capitalization:		
Long-Term Debt	2,521,753	2,521,102
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	1,613,503	1,605,275
Retained Earnings	735,948	734,561
Accumulated Other Comprehensive Loss	(2,251)	(2,713)
Common Stockholder's Equity	2,407,552	2,397,475
Total Capitalization	5,045,505	5,034,777
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 8,791,396	$ 8,255,192

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)	2011	2010	2009
Operating Revenues	$ 2,548,387	$ 2,999,102	$ 3,424,538
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	929,865	1,253,329	1,690,671
Other Operating Expenses	570,519	524,328	571,024
Maintenance	148,999	96,522	117,822
Depreciation	157,747	172,167	186,922
Amortization of Regulatory Assets, Net	65,189	83,906	45,821
Amortization of Rate Reduction Bonds	-	167,021	155,938
Taxes Other Than Income Taxes	212,885	214,179	191,234
Total Operating Expenses	2,085,204	2,511,452	2,959,432
Operating Income	463,183	487,650	465,106
Interest Expense:			
Interest on Long-Term Debt	131,918	134,553	133,422
Interest on Rate Reduction Bonds	-	7,542	19,061
Other Interest	809	(4,357)	3,334
Interest Expense	132,727	137,738	155,817
Other Income, Net	9,741	26,669	25,874
Income Before Income Tax Expense	340,197	376,581	335,163
Income Tax Expense	90,033	132,438	118,847
Net Income	$ 250,164	$ 244,143	$ 216,316

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 250,164	$ 244,143	$ 216,316
Other Comprehensive Income, Net of Tax:			
Qualified Cash Flow Hedging Instruments	445	444	445
Changes in Unrealized Gains/(Losses) on Other Securities	17	14	(30)
Other Comprehensive Income, Net of Tax	462	458	415
Comprehensive Income	$ 250,626	$ 244,601	$ 216,731

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 Stock Information)	Common Stock Stock	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
Balance as of January 1, 2009	6,035,205	$ 60,352	$ 1,454,198	$ 617,276	$ (3,586)	$ 2,128,240
Adoption of Accounting Guidance for Other-Than-Temporary Impairments				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
Net Income				244,143		244,143
Dividends on Preferred Stock				(6,101)		(6,101)
Dividends on Common Stock				(217,691)		(217,691)
Allocation of Benefits - ESOP			919			919
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			2,513			2,513
Other Comprehensive Income					458	458
Balance as of December 31, 2010	6,035,205	60,352	1,605,275	734,561	(2,713)	2,397,475
Net Income				250,164		250,164
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(243,218)		(243,218)
Allocation of Benefits - ESOP			1,429			1,429
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			6,748			6,748
Other Comprehensive Income					462	462
Balance as of December 31, 2011	6,035,205	$ 60,352	$ 1,613,503	$ 735,948	$ (2,251)	$ 2,407,552

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)	2011	2010	2009
Operating Activities:			
Net Income	$ 250,164	$ 244,143	$ 216,316
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	3,215	7,484	15,276
Depreciation	157,747	172,167	186,922
Deferred Income Taxes	112,620	115,069	52,900
Pension and PBOP Expense, Net of PBOP Contributions	10,664	1,595	(10,709)
Regulatory (Under)/Over Recoveries, Net	(86,666)	32,492	51,292
Amortization of Regulatory Assets, Net	65,189	83,906	45,821
Amortization of Rate Reduction Bonds	-	167,021	155,938
Other	(36,928)	(55,515)	(38,731)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	14,610	1,895	50,327
Materials and Supplies	(2,206)	3,377	(6,339)
Taxes Receivable/Accrued	2,719	(56,002)	25,823
Accounts Payable	8,864	(35,976)	(85,773)
Other Current Assets and Liabilities	13,291	15,649	5,718
Net Cash Flows Provided by Operating Activities	513,283	697,305	664,781
Investing Activities:			
Investments in Property, Plant and Equipment	(424,865)	(380,304)	(435,723)
Decrease/(Increase) in NU Money Pool Lending	-	97,775	(97,775)
Proceeds from Sale of Assets	46,841	-	-
Other Investing Activities	16,001	5,385	4,888
Net Cash Flows Used in Investing Activities	(362,023)	(277,144)	(528,610)
Financing Activities:			
Cash Dividends on Common Stock	(243,218)	(217,691)	(113,848)
Cash Dividends on Preferred Stock	(5,559)	(5,559)	(5,559)
Increase/(Decrease) in Short-Term Debt	31,000	-	(187,973)
Increase/(Decrease) in NU Money Pool Borrowings	52,300	6,225	(102,725)
Issuance of Long-Term Debt	245,500	-	312,000
Retirements of Long-Term Debt	(245,500)	-	-

Capital Contributions from NU Parent	6,748	2,513	147,591
Retirements of Rate Reduction Bonds	-	(195,587)	(182,608)
Other Financing Activities	(2,292)	(345)	(3,004)
Net Cash Flows Used in Financing Activities	(161,021)	(410,444)	(136,126)
Net (Decrease)/Increase in Cash	(9,761)	9,717	45
Cash - Beginning of Year	9,762	45	-
Cash - End of Year	$ 1	$ 9,762	$ 45

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

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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, 2011.

February 24, 2012

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, 2011 and 2010 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, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15 of Part IV. We also have audited the Company's internal control over financial reporting as of December 31, 2011 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, 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 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, 2011, 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

Hartford, Connecticut

February 24, 2012

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2011	2010
ASSETS		
Current Assets:		
Cash	$ 56	$ 2,559
Receivables, Net	87,545	105,070
Accounts Receivable from Affiliated Companies	1,294	858
Notes Receivable from Affiliated Companies	55,900	-
Unbilled Revenues	45,403	48,691
Taxes Receivable	7,424	12,564
Fuel, Materials and Supplies	124,744	116,074
Regulatory Assets	34,178	39,215
Prepayments and Other Current Assets	27,837	20,098
Total Current Assets	384,381	345,129
Property, Plant and Equipment, Net	2,256,688	2,053,281
Deferred Debits and Other Assets:		
Regulatory Assets	393,941	395,203
Other Long-Term Assets	81,531	85,508
Total Deferred Debits and Other Assets	475,472	480,711
Total Assets	$ 3,116,541	$ 2,879,121

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)	2011	2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ -	$ 30,000
Notes Payable to Affiliated Companies	-	47,900
Accounts Payable	106,377	85,324
Accounts Payable to Affiliated Companies	18,895	20,007
Accrued Interest	9,670	10,231
Regulatory Liabilities	24,500	8,365
Derivative Liabilities	-	12,834
Other Current Liabilities	36,497	36,726
Total Current Liabilities	195,939	251,387
Rate Reduction Bonds	85,368	138,247
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	392,712	314,996
Regulatory Liabilities	54,415	58,631
Accrued Pension, SERP and PBOP	258,718	296,102
Other Long-Term Liabilities	53,304	56,946
Total Deferred Credits and Other Liabilities	759,149	726,675
Capitalization:		
Long-Term Debt	997,722	836,365
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	700,285	579,577
Retained Earnings	388,910	347,471
Accumulated Other Comprehensive Loss	(10,832)	(601)
Common Stockholder's Equity	1,078,363	926,447
Total Capitalization	2,076,085	1,762,812
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 3,116,541	$ 2,879,121

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)	2011	2010	2009
Operating Revenues	$ 1,013,003	$ 1,033,439	$ 1,109,591
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	308,777	363,147	520,529
Other Operating Expenses	217,119	230,210	239,650
Maintenance	93,079	82,384	87,026
Depreciation	76,167	67,237	61,961
Amortization of Regulatory Assets/(Liabilities), Net	25,383	11,232	(29,619)
Amortization of Rate Reduction Bonds	53,389	50,357	47,482
Taxes Other Than Income Taxes	58,985	52,686	47,975
Total Operating Expenses	832,899	857,253	975,004
Operating Income	180,104	176,186	134,587
Interest Expense:			
Interest on Long-Term Debt	36,832	36,220	33,045
Interest on Rate Reduction Bonds	6,276	9,660	13,128
Other Interest	1,039	1,187	316
Interest Expense	44,147	47,067	46,489
Other Income, Net	14,255	11,749	9,462
Income Before Income Tax Expense	150,212	140,868	97,560
Income Tax Expense	49,945	50,801	31,990
Net Income	$ 100,267	$ 90,067	$ 65,570

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 100,267	$ 90,067	$ 65,570
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	(10,260)	87	87
Changes in Unrealized Gains/(Losses) on Other Securities	29	24	(50)
Other Comprehensive Income/(Loss), Net of Tax	(10,231)	111	37
Comprehensive Income	$ 90,036	$ 90,178	$ 65,607

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 Stock Information)	Common Stock Stock	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
Balance as of January 1, 2009	301	$ -	$ 351,245	$ 283,219	$ (749)	$ 633,715
Adoption of Accounting Guidance for Other-Than-Temporary Impairments				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
Net Income				90,067		90,067
Dividends on Common Stock				(50,584)		(50,584)
Allocation of Benefits - ESOP			439			439
Capital Contributions from NU Parent			158,969			158,969
Other Comprehensive Income					111	111
Balance as of December 31, 2010	301	-	579,577	347,471	(601)	926,447
Net Income				100,267		100,267
Dividends on Common Stock				(58,828)		(58,828)
Allocation of Benefits - ESOP			678			678
Capital Contributions from NU Parent			120,030			120,030
Other Comprehensive Loss					(10,231)	(10,231)
Balance as of December 31, 2011	301	$ -	$ 700,285	$ 388,910	$ (10,832)	$ 1,078,363

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

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

	For the Years Ended December 31,		
(Thousands of Dollars)	2011	2010	2009
Operating Activities:			
Net Income	$ 100,267	$ 90,067	$ 65,570
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	7,035	8,858	10,084
Depreciation	76,167	67,237	61,961
Deferred Income Taxes	75,628	39,225	35,270
Pension and PBOP Expense	27,298	29,112	22,494
Pension and PBOP Contributions	(121,178)	(53,689)	(6,975)
Regulatory Over/(Under) Recoveries, Net	6,079	(2,834)	(4,392)
Amortization of Regulatory Assets/(Liabilities), Net	25,383	11,232	(29,619)
Amortization of Rate Reduction Bonds	53,389	50,357	47,482
Insurance Proceeds	-	10,000	10,066
Settlements of Cash Flow Hedge Instruments	(18,072)	-	-
Other	(20,958)	(41,590)	(7,526)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	7,833	(24,497)	1,505
Fuel, Materials and Supplies	(9,873)	14,891	59
Taxes Receivable/Accrued	5,139	10,037	(13,791)
Accounts Payable	(4,517)	(14,427)	(77,738)
Other Current Assets and Liabilities	(4,915)	1,294	(9,192)
Net Cash Flows Provided by Operating Activities	204,705	195,273	105,258
Investing Activities:			
Investments in Property, Plant and Equipment	(241,772)	(296,335)	(266,440)
(Increase)/Decrease in NU Money Pool Lending	(55,900)	-	53,800
Other Investing Activities	2,089	(7,819)	(1,278)
Net Cash Flows Used in Investing Activities	(295,583)	(304,154)	(213,918)
Financing Activities:			
Cash Dividends on Common Stock	(58,828)	(50,584)	(40,844)
(Decrease)/Increase in Short-Term Debt	(30,000)	30,000	(45,227)
Issuance of Long-Term Debt	282,000	-	150,000
Retirements of Long-Term Debt	(119,800)	-	-
	(47,900)	21,200	26,700

(Decrease)/Increase in NU Money Pool Borrowings						
Capital Contributions from NU Parent		120,030		158,969		68,946
Retirements of Rate Reduction Bonds		(52,879)		(49,867)		(47,026)
Other Financing Activities		(4,248)		(252)		(2,110)
Net Cash Flows Provided by Financing Activities		88,375		109,466		110,439
Net (Decrease)/Increase in Cash		(2,503)		585		1,779
Cash - Beginning of Year		2,559		1,974		195
Cash - End of Year	$	56	$	2,559	$	1,974

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

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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, 2011.

February 24, 2012

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, 2011 and 2010 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, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15 of Part IV. We also have audited the Company's internal control over financial reporting as of December 31, 2011 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, 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 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, 2011, 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

Hartford, Connecticut

February 24, 2012

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2011	2010
ASSETS		
Current Assets:		
Cash	$ 1	$ 1
Receivables, Net	42,757	37,585
Accounts Receivable from Affiliated Companies	633	505
Notes Receivable from Affiliated Companies	11,000	-
Unbilled Revenues	16,277	16,578
Taxes Receivable	2,263	7,346
Materials and Supplies	3,333	3,664
Regulatory Assets	35,520	19,531
Marketable Securities	26,335	33,194
Prepayments and Other Current Assets	3,123	1,968
Total Current Assets	141,242	120,372
Property, Plant and Equipment, Net	1,077,833	817,146
Deferred Debits and Other Assets:		
Regulatory Assets	233,247	207,584
Marketable Securities	30,794	23,860
Other Long-Term Assets	19,777	30,597
Total Deferred Debits and Other Assets	283,818	262,041
Total Assets	$ 1,502,893	$ 1,199,559

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2011	2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ -	$ 20,400
Accounts Payable	111,566	48,344
Accounts Payable to Affiliated Companies	10,626	7,848
Accrued Interest	7,714	6,787
Regulatory Liabilities	33,056	7,959
Accumulated Deferred Income Taxes	-	5,902
Other Current Liabilities	13,041	9,842
Total Current Liabilities	176,003	107,082
Rate Reduction Bonds	26,892	43,325
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	244,511	218,063
Regulatory Liabilities	16,597	15,048
Accrued Pension, SERP and PBOP	29,546	15,315
Other Long-Term Liabilities	47,498	42,854
Total Deferred Credits and Other Liabilities	338,152	291,280
Capitalization:		
Long-Term Debt	499,545	400,288
Common Stockholder's Equity:		
Common Stock	10,866	10,866
Capital Surplus, Paid In	340,115	248,044
Retained Earnings	115,506	98,757
Accumulated Other Comprehensive Loss	(4,186)	(83)
Common Stockholder's Equity	462,301	357,584
Total Capitalization	961,846	757,872
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 1,502,893	$ 1,199,559

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)	2011	2010	2009
Operating Revenues	$ 417,315	$ 395,161	$ 402,413
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	145,594	157,276	192,177
Other Operating Expenses	98,328	102,053	85,591
Maintenance	17,734	19,196	17,895
Depreciation	26,455	23,561	22,454
Amortization of Regulatory Assets/(Liabilities), Net	6,361	2,395	(2,980)
Amortization of Rate Reduction Bonds	16,523	15,494	14,521
Taxes Other Than Income Taxes	17,957	16,529	14,174
Total Operating Expenses	328,952	336,504	343,832
Operating Income	88,363	58,657	58,581
Interest Expense:			
Interest on Long-Term Debt	20,023	17,988	14,074
Interest on Rate Reduction Bonds	2,335	3,372	4,335
Other Interest	1,254	479	877
Interest Expense	23,612	21,839	19,286
Other Income, Net	1,489	2,597	1,824
Income Before Income Tax Expense	66,240	39,415	41,119
Income Tax Expense	23,186	16,325	14,923
Net Income	$ 43,054	$ 23,090	$ 26,196

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 43,054	$ 23,090	$ 26,196
Other Comprehensive Loss, Net of Tax:			
Qualified Cash Flow Hedging Instruments	(4,108)	(79)	(79)
Changes in Unrealized Gains/(Losses) on Other Securities	5	4	(119)
Other Comprehensive Loss, Net of Tax	(4,103)	(75)	(198)
Comprehensive Income	$ 38,951	$ 23,015	$ 25,998

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

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

(Thousands of Dollars, Except Stock Information)	Common Stock Stock	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
Balance as of January 1, 2009	434,653	$ 10,866	$ 144,545	$ 82,549	$ 190	$ 238,150
Adoption of Accounting Guidance for Other-Than-Temporary Impairments				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
Net Income				23,090		23,090
Dividends on Common Stock				(14,882)		(14,882)
Allocation of Benefits - ESOP			165			165
Capital Contributions from NU Parent			102,479			102,479
Other Comprehensive Loss					(75)	(75)
Balance as of December 31, 2010	434,653	10,866	248,044	98,757	(83)	357,584
Net Income				43,054		43,054
Dividends on Common Stock				(26,305)		(26,305)
Allocation of Benefits - ESOP			259			259
Capital Contributions from NU Parent			91,812			91,812
Other Comprehensive Loss					(4,103)	(4,103)
Balance as of December 31, 2011	434,653	$ 10,866	$ 340,115	$ 115,506	$ (4,186)	$ 462,301

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2011	2010	2009
Operating Activities:			
Net Income	$ 43,054	$ 23,090	$ 26,196
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	3,133	9,747	7,590
Depreciation	26,455	23,561	22,454
Deferred Income Taxes	23,056	10,963	22,908
Pension and PBOP Expense, Net of PBOP Contributions	1,722	(535)	(2,630)
Regulatory Over/(Under) Recoveries, Net	1,459	(11,551)	589
Amortization of Regulatory Assets/(Liabilities), Net	6,361	2,395	(2,980)
Amortization of Rate Reduction Bonds	16,523	15,494	14,521
Settlement of Cash Flow Hedge Instrument	(6,859)	-	-
Other	(5,441)	(7,032)	(5,547)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(7,263)	(6,838)	3,757
Materials and Supplies	331	4,650	(4,489)
Taxes Receivable/Accrued	5,084	(393)	1,307
Accounts Payable	12,956	(92)	(19,397)
Other Current Assets and Liabilities	3,824	2,406	(2,150)
Net Cash Flows Provided by Operating Activities	124,395	65,865	62,129
Investing Activities:			
Investments in Property, Plant and Equipment	(237,996)	(115,178)	(105,440)
Proceeds from Sales of Marketable Securities	125,157	114,191	106,308
Purchases of Marketable Securities	(125,453)	(114,587)	(106,937)
Increase in NU Money Pool Lending	(11,000)	-	-
Other Investing Activities	(1,919)	(888)	1,298
Net Cash Flows Used in Investing Activities	(251,211)	(116,462)	(104,771)
Financing Activities:			
Cash Dividends on Common Stock	(26,305)	(14,882)	(18,203)
Decrease in Short-Term Debt	-	-	(29,850)
Issuance of Long-Term Debt	100,000	95,000	-
	(20,400)	(115,700)	104,500

(Decrease)/Increase in NU Money Pool Borrowings						
Retirements of Rate Reduction Bonds		(16,433)		(15,410)		(14,441)
Capital Contributions from NU Parent		91,812		102,479		863
Other Financing Activities		(1,858)		(890)		(226)
Net Cash Flows Provided by Financing Activities		126,816		50,597		42,643
Net Increase in Cash		-		-		1
Cash - Beginning of Year		1		1		-
Cash - End of Year	$	1	$	1	$	1

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Refer to the Glossary of Terms included in this combined Annual Report on Form 10-K for abbreviations and acronyms used throughout the combined notes to the consolidated financial statements.

1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A.

Pending Merger with NSTAR

On October 18, 2010, NU and NSTAR announced that each company's Board of Trustees unanimously approved a merger agreement (the agreement), under which NSTAR will become a direct wholly owned subsidiary of NU. The transaction is structured as a merger of equals in a tax-free exchange of shares. Under the terms of the agreement, NSTAR shareholders will receive 1.312 NU common shares for each NSTAR common share that they own (the exchange ratio). Shareholders of both NU and NSTAR approved the pending merger at special meetings of shareholders held on March 4, 2011. Post-transaction, NU will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire.

The exchange ratio was structured to result in a no premium merger based on the average closing share price of each company's common shares for the 20 trading days preceding the announcement. Based on the number of NU common shares and NSTAR common shares estimated to be outstanding immediately prior to the closing of the merger, upon such closing, NU will be owned approximately 56 percent by NU shareholders and approximately 44 percent by former NSTAR shareholders. It is anticipated that NU will issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger. Subject to the conditions in the agreement, NU s first quarterly dividend per common share paid after the closing of the merger will be increased to an amount that is at least equal, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing.

At closing, NU will acquire NSTAR and, in accordance with accounting standards for business combinations, account for the transaction as an acquisition of NSTAR by NU.

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. NU and NSTAR are awaiting approvals from PURA and the DPU. PURA is scheduled to issue a final decision on April 2, 2012.

On February 15, 2012, NU and NSTAR reached comprehensive merger-related settlement agreements with both the Massachusetts Attorney General and the DOER. The first settlement agreement covers a variety of rate-making and rate design issues, including a distribution rate freeze until 2016 for WMECO, NSTAR Electric Company and NSTAR Gas Company. The second settlement agreement covers a variety of matters impacting the advancement of Massachusetts clean energy goals established by the Green Communities Act and Global Warming Solutions Act. Pursuant to the terms and provisions of the settlement agreements, all parties agree that the proposed merger between NU and NSTAR is consistent with the public interest and should be approved by the DPU. However, the settlement agreements allow the Attorney General and DOER to terminate their respective agreements for any reason at any time prior to approval by the DPU. All parties to the settlement agreements have requested that the DPU approve the merger on April 4, 2012. Under the terms of the settlement agreements, WMECO would record a $3 million pre-tax charge in 2012 pending completion of the merger.

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 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.

NU and a subsidiary of NSTAR have formed, on a 75 percent and 25 percent basis, respectively, a limited liability company, NPT, to construct, own and operate the Northern Pass transmission project. NPT and Hydro Renewable Energy entered into a TSA whereby NPT will sell to Hydro Renewable Energy electric transmission rights over the Northern Pass for a 40-year term at cost of service rates. NPT will be required to maintain a capital structure of 50 percent debt and 50 percent equity. NU determined, through its controlling financial interest in NPT, that it must consolidate NPT, as NU has the power to direct the activities of NPT, which most significantly impact its economic performance, including permitting and siting and operation and maintenance activities over the term of the TSA.

In accordance with accounting guidance on noncontrolling interests in consolidated financial statements, 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. For the years ended December 31, 2011, 2010 and 2009, there was no change in NU parent's 100 percent ownership of the common equity of CL&P.

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 and NSTAR's portion of the net income of NPT.

As of December 31, 2011, NU, CL&P, PSNH and WMECO have adjusted the presentation of Regulatory Assets and Liabilities to reflect the current portions, and related deferred tax amounts, as current assets and liabilities on the consolidated balance sheets. Amounts as of December 31, 2010 have been reclassified to conform to the December 31, 2011 presentation. For additional information, see Note 2, Regulatory Accounting, to the consolidated financial statements.

Certain other reclassifications of prior year data were made in the accompanying consolidated balance sheets for all companies presented and statements of cash flows for NU and PSNH. These reclassifications were made to conform to the current year s presentation.

NU evaluates events and transactions that occur after the balance sheet date but before financial statements are issued and recognizes 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 discloses, but does not recognize, in the financial statements subsequent events that provide evidence about the conditions that arose after the balance sheet date but before the financial statements are issued. NU did not identify any such events that required recognition or disclosure under this guidance.

C.

About NU, CL&P, PSNH and WMECO

Consolidated: NU is the parent company of CL&P, PSNH, WMECO, and other subsidiaries. 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, natural gas became an integral part of NU's Connecticut operations when NU's merger with Yankee and its principal subsidiary, Yankee Gas, was completed. NU, 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. Arrangements among the regulated electric companies and other NU companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. The Regulated companies are subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the PURA for CL&P and Yankee Gas, the NHPUC as well as certain regulatory oversight by the Vermont Department of Public Service and the Maine Public Utilities Commission for PSNH, and the 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 and WMECO's distribution results include the operations of their respective generation businesses. Yankee Gas' results include the operations of its natural gas distribution segment. NPT was formed to construct, own and operate the Northern Pass line, a new HVDC transmission line from Québec to New Hampshire that will interconnect with a new HVDC transmission line being developed by a transmission subsidiary of HQ.

Other: As of December 31, 2011, NU Enterprises primary business consisted of Select Energy s remaining energy wholesale marketing contracts and NGS operation and maintenance agreements as well as its subsidiary, Boulos, an electrical contractor based in Maine that NU Enterprises continues to own and manage. NUSCO, RRR, Renewable Properties, Inc. and Properties, Inc. provide support services to NU, including its regulated companies.

D.

Accounting Standards Issued But Not Yet Adopted

In May 2011, the Financial Accounting Standards Board and the International Accounting Standards Board issued a final Accounting Standards Update on fair value measurement, effective January 1, 2012, that is not expected to have an impact on NU s financial position, results of operations or cash flows, but will require additional financial statement disclosures related to fair value measurements.

In September 2011, the Financial Accounting Standards Board issued a final Accounting Standards Update on testing goodwill for impairment, effective January 1, 2012 with early adoption permitted. The standard provides the option to perform a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying value; if so, quantitative testing is required. The standard does not change existing guidance relating to when an entity should test goodwill for impairment or the methodology to be utilized in performing quantitative testing. The standard will not have an impact on NU s financial position, results of operations or cash flows.

E.

Cash and Cash Equivalents

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

F.

Provision for Uncollectible Accounts

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

The provision for uncollectible accounts, which is included in Receivables, Net on the accompanying consolidated balance sheets, is as follows:

	As of December 31,	
(Millions of Dollars)	**2011**	**2010**
NU	$ 34.9	$ 39.8
CL&P	14.8	17.2
PSNH	7.2	6.8
WMECO	4.6	6.0

The PURA allows CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. As a result of the January 2011 DPU rate case decision, WMECO is allowed to recover amounts associated with uncollectible hardship receivables in rates. As of December 31, 2011, CL&P, WMECO and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $68.6 million, $5.4 million and $6.8 million, respectively, with the corresponding bad debt expense recorded as Regulatory Assets or Other Long-Term Assets as these amounts are probable of recovery. As of December 31, 2010, these amounts totaled $65 million, $6.9 million and $7.5 million, respectively.

G.

Fuel, Materials and Supplies and Allowance Inventory

Fuel, Materials and Supplies include natural gas, coal, oil and materials purchased primarily for construction or operation and maintenance purposes. Natural gas inventory, coal and oil are valued at their respective weighted average cost. Materials and supplies are valued at the lower of average cost or market.

PSNH is subject to federal and state laws and regulations that regulate emissions of air pollutants, including SO_2, CO_2, and NO_x related to its regulated generation units, and uses SO_2, CO_2, and NO_x emissions allowances. At the end of each compliance period, PSNH is required to relinquish SO_2, CO_2, and NO_x emissions allowances corresponding to the actual respective emissions emitted by its generating units over the compliance period. SO_2 and NO_x emissions allowances are obtained through an annual allocation from the federal and state regulators that are granted at no cost and through purchases from third parties. CO_2 emissions allowances are acquired through auctions and through purchases from third parties.

SO_2, CO_2, and NO_x emissions allowances are recorded within Fuel, Materials and Supplies and are classified on the balance sheet as short-term or long-term depending on the period in which they are expected to be utilized against actual emissions. As of December 31, 2011 and 2010, PSNH had \$0.8 million and \$7.1 million, respectively, of short-term SO_2, CO_2, and NO_x emissions allowances classified as Fuel, Materials and Supplies on the accompanying consolidated balance sheets and \$19.4 million and \$18.2 million, respectively, of long-term SO_2 and CO_2 emissions allowances classified as Other Long-Term Assets on the accompanying consolidated balance sheets.

SO_2, CO_2, and NO_x emissions allowances are charged to expense based on their weighted average cost as they are utilized against emissions volumes at PSNH's generating units. PSNH recorded expenses of \$5.1 million, \$6.6 million and \$7.6 million for the years ended December 31, 2011, 2010, and 2009, respectively, which were included in Fuel, Purchased and Net Interchange Power on the accompanying consolidated statements of income. These costs are recovered from customers through PSNH ES revenues.

H.

Restricted Cash and Other Deposits

As of December 31, 2011, NU, CL&P and PSNH had \$17.9 million, \$9.4 million, and \$7 million, respectively, of restricted cash, primarily relating to amounts held in escrow related to property damage at CL&P and insurance proceeds on bondable property at PSNH, which were included in Prepayments and Other Current Assets on the accompanying consolidated balance sheets. There was no restricted cash held as of December 31, 2010.

As of December 31, 2011, PSNH and WMECO, and as of December 31, 2010, CL&P, PSNH and WMECO, had amounts on deposit related to subsidiaries used to facilitate the issuance of RRBs. In addition, NU, CL&P, PSNH and WMECO had other cash deposits held with unaffiliated parties, including deposits related to Select Energy s position in transactions with counterparties, as of December 31, 2011 and 2010. These amounts are included in Prepayments and Other Current Assets and Other Long-Term Assets on the accompanying consolidated balance sheets. These amounts were as follows:

NU	**As of December 31,**	
(Millions of Dollars)	**2011**	**2010**
Rate Reduction Bond Deposits	\$ 29.5	\$ 53.1
Other Deposits	17.7	29.9

	As of December 31,					
	2011			**2010**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Rate Reduction Bond Deposits	\$ -	\$ 24.4	\$ 5.1	\$ 22.1	\$ 26.9	\$ 4.1
Other Deposits	1.1	2.5	2.2	2.1	2.8	1.2

I.

Fair Value Measurements

NU, including CL&P, PSNH, and WMECO, applies fair value measurement guidance to all derivative contracts 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 is also applied 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.

Fair Value Hierarchy: In measuring fair value, NU uses observable market data when available and minimizes the use of unobservable inputs. 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. NU evaluates the classification of assets and liabilities measured at fair value on a quarterly basis, and NU's policy is to recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. 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.

Determination of Fair Value: The valuation techniques and inputs used in NU's fair value measurements are described in Note 4, Derivative Instruments, and Note 5, Marketable Securities, to the consolidated financial statements.

J.

Derivative Accounting

Most of CL&P, PSNH and WMECO s contracts for the purchase and sale of energy or energy-related products are derivatives, along with all but one of NU Enterprises' 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 effectiveness, 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 the contract has a determinable quantity 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. 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.

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 in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting is terminated and fair value accounting is applied prospectively.

The remaining wholesale marketing contracts that 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 4, Derivative Instruments, to the consolidated financial statements.

K.

Equity Method Investments

Regional Nuclear Companies: As of December 31, 2011, CL&P, PSNH and WMECO owned common stock in three regional nuclear generation companies (Yankee Companies). Each of the Yankee Companies owned a single nuclear generating facility that has been decommissioned. Ownership interests in the Yankee Companies as of December 31, 2011, which are accounted for on the equity method, are as follows:

(Percent)	**CYAPC**	**YAEC**	**MYAPC**
CL&P	34.5	24.5	12.0
PSNH	5.0	7.0	5.0
WMECO	9.5	7.0	3.0
Total NU	49.0%	38.5%	20.0%

The total carrying values of ownership interests in CYAPC, YAEC and MYAPC, which are included in Other Long-Term Assets on the accompanying consolidated balance sheets and in the Regulated companies - Electric distribution reportable segment, are as follows:

(Millions of Dollars)		**2011**		**2010**
CL&P	$	1.4	$	1.3
PSNH		0.3		0.3
WMECO		0.4		0.4
Total NU	$	2.1	$	2.0

For further information on the Yankee Companies, see Note 12C, Commitments and Contingencies - Deferred Contractual Obligations, to the consolidated financial statements.

Other: NU has a 22.7 percent equity ownership interest in two companies that transmit electricity imported from the Hydro-Québec system in Canada. NU s investment totaled $4.6 million and $5.6 million as of December 31, 2011 and 2010, respectively. As of December 31, 2011, NU also had an equity ownership of $4.2 million in an energy investment fund.

These equity investments are included in Other Long-Term Assets on the accompanying consolidated balance sheets and net earnings related to these equity investments are included in Other Income, Net on the accompanying consolidated statements of income.

L.

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. Beginning in 2011, WMECO was allowed to establish a revenue decoupling mechanism to recover a pre-established level of baseline distribution delivery service revenues of $125.6 million per year, independent of actual customer usage. Such decoupling mechanisms effectively break the relationship between kWhs consumed by customers and revenues recognized.

Energy purchases under derivative instruments are recorded in Fuel, Purchased and Net Interchange Power, and sales of energy associated with these purchases are recorded in Operating Revenues.

Regulated Companies' Unbilled Revenues: Unbilled revenues represent an estimate of electricity or natural 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 method. The daily load cycle 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 month load, net of delivery losses, to estimate unbilled sales. Unbilled revenues are estimated by first allocating sales to the respective customer classes, then applying an average rate by customer class 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. Wholesale transmission revenues for CL&P, PSNH, and WMECO are collected under the ISO-NE FERC, Transmission, Markets and Services Tariff (ISO-NE Tariff). The ISO-NE Tariff includes 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 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. 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 of CL&P's, PSNH's and WMECO's regional and local revenue requirements as prescribed in the ISO-NE Tariff. Both the RNS and Schedule 21 - NU rates provide for the annual reconciliation and recovery or refund of estimated (or projected) costs to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from, or refunded to, transmission customers. As of December 31, 2011, the Schedule 21 - NU rates were in a total overrecovery position of $31.4 million ($18.6 million for CL&P, $1.7 million for PSNH and $11.1 million for WMECO), which will be refunded to transmission customers in June 2012.

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 electric distribution companies to charge their retail customers for transmission costs on a timely basis.

M.

Operating Expenses

Costs related to fuel (and natural gas costs as it related to Yankee Gas) included in Fuel, Purchased and Net Interchange Power on the accompanying consolidated statements of income were as follows:

	For the Years Ended December 31,					
(Millions of Dollars)	2011		2010		2009	
NU	$	307.9	$	391.6	$	401.7
PSNH		115.9		184.3		174.1
Yankee Gas		191.3		206.4		226.1

N.

Allowance for Funds Used During Construction

AFUDC is included in the cost of the Regulated companies' utility plant and represents the cost of borrowed and equity funds used to finance construction. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of Other Interest Expense, and the AFUDC related to equity funds is recorded as Other Income, Net on the accompanying consolidated statements of income.

NU	For the Years Ended December 31,					
(Millions of Dollars, except percentages)	2011		2010		2009	
AFUDC:						
Borrowed Funds	$	11.8	$	10.2	$	5.9
Equity Funds		22.5		16.7		9.4
Total	$	34.3	$	26.9	$	15.3
Average AFUDC Rate		7.3%		7.1%		6.1%

	For the Years Ended December 31,								
	2011			2010			2009		
(Millions of Dollars, except percentages)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
AFUDC:									

Borrowed Funds	$	3.3	$	7.1	$	0.5	$	2.7	$	6.6	$	0.3	$	2.2	$	3.1	$	0.2
Equity Funds		6.0		13.2		1.0		4.9		10.4		0.6		5.7		3.6		-
Total	$	9.3	$	20.3	$	1.5	$	7.6	$	17.0	$	0.9	$	7.9	$	6.7	$	0.2
Average AFUDC Rate		8.3%		7.1%		7.4%		8.3%		6.8%		6.4%		7.2%		6.2%		1.7%

The Regulated companies' average AFUDC rate is based on a FERC-prescribed formula that produces an average rate using the cost of a company's short-term financings as well as a company's capitalization (preferred stock, long-term debt and common equity). The average rate is applied to average eligible CWIP amounts to calculate AFUDC.

O.

Other Income, Net

The other income/(loss) items included within Other Income, Net on the accompanying consolidated statements of income primarily consist of investment income/(loss), interest income, AFUDC related to equity funds and equity in earnings, which relates to the Company's investments, including investments of CL&P, PSNH and WMECO in the Yankee Companies and NU's investment in two regional transmission companies.

P.

Other Taxes

Certain excise taxes levied by state or local governments are collected by CL&P and Yankee Gas from their respective customers. These excise taxes are shown on a gross basis with collections in revenues and payments in expenses. Gross receipts taxes, franchise taxes and other excise taxes were included in Operating Revenues and Taxes Other Than Income Taxes on the accompanying consolidated statements of income as follows:

	For the Years Ended December 31,					
(Millions of Dollars)	**2011**		**2010**		**2009**	
NU	$	137.8	$	143.7	$	135.6
CL&P		121.6		128.0		119.0

Certain sales taxes are also collected by CL&P, WMECO, and Yankee Gas from their respective customers as agents for state and local governments and are recorded on a net basis with no impact on the accompanying consolidated statements of income.

Q. Supplemental Cash Flow Information

NU	For the Years Ended December 31,		
(Millions of Dollars)	**2011**	**2010**	**2009**

Cash Paid/(Received) During the Year for:						
Interest, Net of Amounts Capitalized	$	256.3	$	258.3	$	263.8
Income Taxes		(76.6)		84.5		35.1
Non-Cash Investing Activities:						
Capital Expenditures Incurred But Not Paid		168.5		127.9		125.5

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	For the Years Ended December 31,								
	2011			2010			2009		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Cash Paid/(Received) During the Year for:									
Interest, Net of Amounts Capitalized	$ 136.6	$ 49.3	$ 22.1	$ 142.2	$ 51.4	$ 20.2	$ 146.7	$ 49.0	$ 19.4
Income Taxes	(27.5)	(29.0)	(4.9)	71.5	1.6	5.0	42.4	12.8	(9.1)
Non-Cash Investing Activities:									
Capital Expenditures Incurred But Not Paid	32.7	51.1	61.3	46.2	35.8	21.2	48.2	46.5	10.3

The majority of the short-term borrowings of NU, including CL&P, PSNH and WMECO, have original maturities of three months or less. Accordingly, borrowings and repayments are shown net on the statement of cash flows.

R.

Self-Insurance Accruals

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

S.

Related Parties

Several wholly owned subsidiaries of NU provide support services for NU, including CL&P, PSNH and WMECO. NUSCO provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. RRR, Renewable Properties, Inc. and Properties, Inc., three other NU subsidiaries, construct, acquire or lease some of the property and facilities used by NU's companies.

As of both December 31, 2011 and 2010, CL&P, PSNH and WMECO had long-term receivables from NUSCO in the amount of $25 million, $3.8 million and $5.5 million, respectively, which are included in Other Long-Term Assets on the accompanying consolidated balance sheets related to the funding of investments held in trust by NUSCO in connection with certain postretirement benefits for CL&P, PSNH and WMECO employees. These amounts have been eliminated in consolidation on the NU financial statements.

Included in the CL&P, PSNH and WMECO consolidated balance sheets as of December 31, 2011 and 2010 are Accounts Receivable from Affiliated Companies and Accounts Payable to Affiliated Companies relating to transactions between CL&P, PSNH and WMECO and other subsidiaries that are wholly owned by NU. These amounts have been eliminated in consolidation on the NU financial statements.

The NU Foundation is an independent not-for-profit charitable entity designed to fund initiatives or entities that emphasize economic development, workforce training and education, and a clean and healthy environment. The board of directors of the NU Foundation consists of certain NU officers. The NU Foundation is not included in the consolidated financial statements of NU as it is a not-for-profit entity and the Company does not have title to the NU Foundation's assets and cannot receive contributions back from the NU Foundation. NU did not make any contributions to the NU Foundation in 2011 or 2009. NU, CL&P, PSNH and WMECO recorded aggregate contributions to the NU Foundation of $2 million in 2010.

2.

REGULATORY ACCOUNTING

The Regulated companies continue to be rate-regulated on a cost-of-service basis; therefore, 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.

Management believes it is probable that the Regulated companies will recover their respective investments in long-lived assets, including regulatory assets. If management determined that it could no longer apply the accounting guidance applicable to rate-regulated enterprises to the Regulated companies' operations, or that management could not conclude it is probable that costs would be recovered or reflected in future rates, the costs would be charged to net income in the period in which the determination is made.

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

NU	**As of December 31,**	
(Millions of Dollars)	**2011**	**2010**
Deferred Benefit Costs	$ 1,360.5	$ 1,094.2
Regulatory Assets Offsetting Derivative Liabilities	939.6	859.7
Securitized Assets	101.8	171.7
Income Taxes, Net	425.4	401.5
Unrecovered Contractual Obligations	100.9	123.2
Regulatory Tracker Deferrals	45.9	70.3
Storm Cost Deferrals	356.0	60.1
Asset Retirement Obligations	47.5	45.3
Losses on Reacquired Debt	24.5	21.5
Deferred Environmental Remediation Costs	38.5	36.8
Deferred Operation and Maintenance Costs	4.0	29.5
Other Regulatory Assets	78.2	81.5
Total Regulatory Assets	$ 3,522.8	$ 2,995.3
Less: Current Portion	$ 255.1	$ 238.7
Total Long-Term Regulatory Assets	$ 3,267.7	$ 2,756.6

	As of December 31,					
	2011			**2010**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Deferred Benefit Costs	$ 572.8	$ 200.0	$ 118.9	$ 471.8	$ 152.6	$ 96.0
Regulatory Assets Offsetting Derivative Liabilities	932.0	-	7.3	846.2	12.8	-
Securitized Assets	-	76.4	25.4	-	129.8	41.9
Income Taxes, Net	339.6	38.0	17.8	328.9	31.4	16.8
Unrecovered Contractual Obligations	80.9	-	20.0	97.9	-	25.3
Regulatory Tracker Deferrals	5.5	11.9	22.1	35.5	14.7	15.2
Storm Cost Deferrals	268.3	44.0	43.7	4.0	40.7	15.4
Asset Retirement Obligations	27.9	13.5	3.2	24.9	14.7	3.0
Losses on Reacquired Debt	13.9	9.0	0.3	11.2	8.4	0.4
Deferred Environmental Remediation Costs	-	9.7	-	-	9.7	-
Deferred Operation and Maintenance Costs	4.0	-	-	29.5	-	-
Other Regulatory Assets	29.1	25.6	10.0	29.0	19.6	13.1
Total Regulatory Assets	$ 2,274.0	$ 428.1	$ 268.7	$ 1,878.9	$ 434.4	$ 227.1
Less: Current Portion	$ 170.2	$ 34.2	$ 35.5	$ 157.5	$ 39.2	$ 19.5
Total Long-Term Regulatory Assets	$ 2,103.8	$ 393.9	$ 233.2	$ 1,721.4	$ 395.2	$ 207.6

Additionally, the Regulated companies had $32.4 million ($5 million for CL&P, $22.4 million for PSNH, and $1.6 million for WMECO) and $37.5 million ($0.6 million for CL&P, $26.5 million for PSNH, and $1.9 million for WMECO) of regulatory costs as of December 31, 2011 and 2010, respectively, which were included in Other Long-Term Assets on the accompanying consolidated balance sheets. 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.

Of the total December 31, 2011 amount, $21.7 million for PSNH related to costs incurred for Tropical Storm Irene and the October snowstorm restorations that met the NHPUC criteria for cost deferral. Refer to the *Storm Cost Deferrals* section below for further discussion.

The December 31, 2010 balance of regulatory costs included in Other Long-Term Assets at PSNH included costs incurred for the February 2010 wind storm restorations that met the NHPUC specified criteria for cost deferral and certain costs related to previously recognized lost tax benefits as a result of a provision in the 2010 Healthcare Act that eliminated the tax deductibility of actuarially equivalent Medicare Part D benefits for retirees. During June 2011, the NHPUC approved these costs for recovery, with a return on the storm costs, and PSNH recorded a regulatory asset of $10.9 million related to the wind storm restoration costs and $7.2 million for the recovery of the lost tax benefits. On July 28, 2010, PURA allowed the creation by CL&P of a regulatory asset for the recovery of lost tax benefits as a result of the 2010 Healthcare Act, subject to review in its next rate case. On January 31, 2011, the DPU allowed the creation by WMECO of a regulatory asset as a result of the 2010 Healthcare Act. NU has concluded that the costs associated with these lost tax benefits are probable of recovery and as of December 31, 2011, $32.2 million ($18.9 million for CL&P, $6.6 million for PSNH, $3.2 million for WMECO and $3.5 million for Yankee Gas) are included in Other Regulatory Assets in the table above. These assets are not earning a return. PSNH and WMECO's costs are being recovered over a period of 5 to 7 years. For further information regarding the 2010 Healthcare Act, see Note 11, Income Taxes, to the consolidated financial statements.

For rate-making purposes, the Regulated companies recover the cost of allowed equity return on certain regulatory assets. This cost, which is not recorded on the accompanying consolidated balance sheets, totaled $3.5 million and $6.1 million for CL&P and $7.6 million and $0.5 million for PSNH as of December 31, 2011 and 2010, respectively. These costs will be recovered in 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 pension and other postretirement plans is recorded with an offset to Accumulated Other Comprehensive Income/(Loss) and is remeasured annually. However, because the Regulated companies are rate-regulated on a cost-of-service basis, offsets were recorded as regulatory assets as of December 31, 2011 and 2010 as these amounts have been, and continue to be, recoverable in cost-of-service regulated rates. Regulatory accounting

was also applied to the portions of the NUSCO costs that support the Regulated companies, as these amounts are also recoverable. The deferred benefit costs of CL&P and PSNH are not in rate base. WMECO's deferred benefit costs are earning an equity return at the same rate as the assets included in rate base. Pension and PBOP costs are expected to be amortized into expense over the average future employee service period of approximately 10 and 9 years, respectively.

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 derivative liabilities relating to CL&P's capacity contracts, referred to as CfDs. See Note 4, Derivative Instruments, to the consolidated financial statements for further information. These assets are excluded from rate base and are being recovered as the actual settlement occurs over the duration of the contracts.

Securitized Assets: 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. These assets are not earning an equity return and are being recovered over the amortization period of their associated RRBs. 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. These assets are excluded from rate base. For further information regarding income taxes, see Note 11, Income Taxes, to the consolidated financial statements.

Unrecovered Contractual Obligations: Under the terms of contracts with CYAPC, YAEC and MYAPC, 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. These obligations for CL&P are earning a return and are being recovered through the CTA. Amounts for WMECO are being recovered without a return 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 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. The reconciliation process produces deferrals for future recovery or refund, which can be either under or over-collections to be included in future customer rates each year. Regulatory tracker deferrals are recorded as regulatory assets if costs are in excess of collections from customers and are recorded as regulatory liabilities if collections from customers are in excess of costs. All material regulatory tracker deferrals that are in a regulatory asset position are earning some form of return. The following regulatory tracker deferrals were recorded as either regulatory assets or liabilities as of December 31, 2011 and 2010:

CL&P Reconciliation Mechanisms: The PURA has established several reconciliation mechanisms, which allow CL&P to recover costs associated with the procurement of energy for SS and LRS, congestion and other costs associated with power market rules approved by the FERC or as approved by the PURA, C&LM programs, the retail transmission of energy, certain regulatory and energy public policy costs, such as hardship protection costs and transition period property taxes, and stranded costs, such as the amortization of regulatory assets and IPP over market costs. As part of the CTA mechanism reconciliation process, CL&P has also established an obligation to refund the variable incentive portion of its transition service procurement fee, which totaled $26.3 million and $24.7 million as of December 31, 2011 and 2010, respectively, and was recorded as a regulatory liability.

PSNH Reconciliation Mechanisms: The NHPUC permits PSNH to recover the costs of providing generation, restructuring costs as a result of deregulation, the retail transmission of energy, and the cost of C&LM programs through various reconciliation mechanisms.

WMECO Reconciliation Mechanisms: The DPU has approved a number of individual cost and revenue requirement recovery mechanisms. These mechanisms recover costs associated with providing energy, retail transmission of energy, administrative costs to procure energy, bad debt costs associated with providing energy, company investments in renewable energy, such as solar, and credits given to customers who generate renewable energy. There is also a mechanism for the recovery of stranded generation costs. Additionally, the DPU has provided cost and revenue requirement recovery mechanisms for certain operating expenses. These individual mechanisms include recovery of pension and PBOP costs, certain state government regulatory review, energy efficiency programs, customer arrearage forgiveness programs and low income customer discounts.

In the January 31, 2011 rate case, WMECO received approval for a revenue decoupling reconciliation mechanism, which provides assurance that WMECO will recover a DPU pre-established level of baseline distribution delivery service revenue to manage all other distribution operating expenses and earn a level of return on its capital investment.

Storm Cost Deferrals: The storm cost deferrals relate to costs incurred at CL&P, PSNH and WMECO for restorations that met regulatory agency specified criteria for cost deferral.

On June 1, 2011, a series of severe thunderstorms with high winds, including tornadoes, struck portions of WMECO s service territory. On June 9, 2011, another series of severe thunderstorms with high winds struck CL&P, PSNH and WMECO's service territories. The cost of restoration that was deferred for future recovery from customers and recorded as a regulatory asset as of December 31, 2011 for CL&P and WMECO totaled $11 million and $3.3 million, respectively.

On August 28, 2011, Tropical Storm Irene caused extensive damage to NU s distribution system. The estimated cost of restoration that was deferred for future recovery from customers and recorded as a regulatory asset as of December 31, 2011 for CL&P and WMECO totaled $105.6 million and $3.2 million, respectively. PSNH recorded $7 million in Other Long-Term Assets as previously described.

On October 29, 2011, an unprecedented storm inundated NU s service territory with heavy snow causing significant damage to NU s distribution and transmission systems. In terms of customer outages, this was the most severe storm in CL&P s history, surpassing Tropical Storm Irene; the third most severe in PSNH s history and the most severe in WMECO's history. The estimated cost of restoration that was deferred for future recovery from customers and recorded as a regulatory asset as of December 31, 2011 for CL&P and WMECO totaled $157.7 million and $23.5 million, respectively. PSNH recorded $14.7 million in Other Long-Term Assets as previously described. The estimated cost of restoration is subject to change as additional cost information becomes available.

Management believes its response to the storm damage was prudent and therefore believes it is probable that CL&P, PSNH and WMECO will be allowed to recover these deferred storm costs. CL&P, PSNH and WMECO will seek recovery of these estimated deferred storm costs through the appropriate regulatory recovery process.

The PSNH deferral as of December 31, 2011 relates to remaining costs incurred for a major storm in December 2008 and the February 2010 wind storm restorations, both of which were approved for recovery and are included in rate base. WMECO's remaining storm deferral relates to 2008 and 2010 storm costs, which were approved for recovery and are earning a return.

Asset Retirement Obligations: The costs associated with the depreciation of the Regulated companies' ARO assets and accretion of the ARO liabilities are recorded as regulatory assets in accordance with regulatory accounting guidance. For CL&P and WMECO, ARO assets, regulatory assets and liabilities offset and are excluded from rate base. PSNH's ARO assets, regulatory assets and liabilities are included in rate base. These costs are being recovered over the life of the underlying property, plant and equipment.

Losses on Reacquired Debt: The regulatory asset relates to the losses associated with the reacquisition or redemption of long-term debt and are amortized over the life of the respective long-term debt issuance. These deferred losses are incorporated as part of debt costs included in the rate of return calculation.

Deferred Environmental Remediation Costs: This regulatory asset relates to environmental remediation costs at PSNH of $9.7 million and Yankee Gas of $28.8 million. Both PSNH and Yankee Gas have regulatory rate recovery mechanisms for environmental costs and accordingly, offsets to environmental reserves were recorded as regulatory assets. Management continues to believe these costs are probable of recovery in future cost-of-service regulated rates.

Deferred Operation and Maintenance Costs: This regulatory asset represents the deferral of maintenance expense in connection with the deferred recovery of revenue requirements for the period July 1, 2010 through December 31, 2010, as allowed by the PURA. CL&P is allowed to recover these costs from January 1, 2011 through June 30, 2012.

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

NU	**As of December 31,**	
(Millions of Dollars)	**2011**	**2010**
Cost of Removal	$ 172.2	$ 194.8
Regulatory Liabilities Offsetting Derivative Assets	-	38.1
Regulatory Tracker Deferrals	139.1	95.1
AFUDC Transmission Incentive	67.0	62.1
Pension Liability - Yankee Gas Acquisition	10.0	12.5
Overrecovered Spent Nuclear Fuel Costs and Contractual Obligations	15.4	14.6
Wholesale Transmission Overcollections	9.6	13.7
Other Regulatory Liabilities	20.6	8.2
Total Regulatory Liabilities	$ 433.9	$ 439.1
Less: Current Portion	$ 167.8	$ 99.4
Total Long-Term Regulatory Liabilities	$ 266.1	$ 339.7

	As of December 31,					
		2011			**2010**	
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Cost of Removal	$ 63.8	$ 53.2	$ 7.2	$ 78.6	$ 57.3	$ 9.5
Regulatory Liabilities Offsetting Derivative Assets	-	-	-	38.1	-	-
Regulatory Tracker Deferrals	94.4	17.3	21.3	79.4	6.6	4.8
AFUDC Transmission Incentive	57.7	-	9.3	56.5	-	5.6
Overrecovered Spent Nuclear Fuel Costs and Contractual Obligations	15.4	-	-	14.6	-	-
Wholesale Transmission Overcollections	4.5	2.6	9.5	13.7	-	-
Other Regulatory Liabilities	11.8	5.8	2.4	1.2	3.1	3.1
Total Regulatory Liabilities	$ 247.6	$ 78.9	$ 49.7	$ 282.1	$ 67.0	$ 23.0
Less: Current Portion	$ 108.3	$ 24.5	$ 33.1	$ 75.7	$ 8.4	$ 8.0
Total Long-Term Regulatory Liabilities	$ 139.3	$ 54.4	$ 16.6	$ 206.4	$ 58.6	$ 15.0

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.

Regulatory Liabilities Offsetting Derivative Assets: The regulatory liabilities offsetting derivative assets relate to the fair value of contracts used to purchase power and other related contracts that will benefit customers in the future. See Note 4, Derivative Instruments, to the consolidated financial statements for further information. This liability is excluded from rate base and is refunded as the actual settlement occurs over the duration of the contracts.

AFUDC Transmission Incentive: AFUDC was recorded on 100 percent of CL&P and WMECO's CWIP for their NEEWS projects through May 31, 2011, all of which was reserved as a regulatory liability to reflect rate base recovery for 100 percent of the CWIP as a result of FERC-approved transmission incentives. Effective June 1, 2011, FERC approved changes to the ISO-NE Tariff in order to include 100 percent of the NEEWS CWIP in regional rate base. As a result, CL&P and WMECO no longer record AFUDC on NEEWS CWIP.

Overrecovered Spent Nuclear Fuel Costs and Contractual Obligations: CL&P and WMECO currently recover amounts in rates for costs of disposal of spent nuclear fuel and high-level radioactive waste for the period prior to the sale of their ownership shares in the Millstone nuclear power stations. Collections in excess of these costs are recorded as regulatory liabilities. CL&P has also established a regulatory liability for the overrecovery of its proportionate share of the remaining costs, including decommissioning, of the MYAPC nuclear facility.

Wholesale Transmission Overcollections: CL&P, PSNH and WMECO's transmission rates recover total transmission revenue requirements, recovering all regional and local revenue requirements for providing transmission service. These rates provide for annual reconciliations to actual costs and the difference between billed and actual costs is deferred. Regulatory liabilities were recorded for collections in excess of costs.

Pension Liability - Yankee Gas Acquisition: When Yankee Gas was acquired by NU, the pension liability was adjusted to fair value with an offset to the adjustment recorded as a regulatory liability, as approved by the PURA. The pension liability was approved for amortization over an approximate 13-year period beginning in 2002.

3. PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

The following tables summarize the NU, CL&P, PSNH and WMECO investments in utility property, plant and equipment:

NU	**As of December 31,**			
(Millions of Dollars)	**2011**		**2010**	
Distribution - Electric	$	6,540.4	$	6,197.2

Distribution - Natural Gas		1,247.6		1,126.6
Transmission		3,541.9		3,378.0
Generation		1,096.0		697.1
Electric and Natural Gas Utility		12,425.9		11,398.9
Other [(1)]		305.1		305.5
Total Property, Plant and Equipment, Gross		12,731.0		11,704.4
Less: Accumulated Depreciation				
Electric and Natural Gas Utility		(3,035.5)		(2,862.3)
Other		(120.2)		(119.9)
Total Accumulated Depreciation		(3,155.7)		(2,982.2)
Property, Plant and Equipment, Net		9,575.3		8,722.2
Construction Work in Progress		827.8		845.5
Total Property, Plant and Equipment, Net	$	10,403.1	$	9,567.7

(1)

These assets are primarily owned by RRR ($161.5 million and $166 million) and NUSCO ($131.5 million and $126.6 million) as of December 31, 2011 and 2010, respectively, and are mainly comprised of building improvements at RRR and software and equipment at NUSCO.

	As of December 31,					
		2011			**2010**	
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Distribution	$ 4,419.6	$ 1,451.6	$ 704.3	$ 4,180.7	$ 1,375.4	$ 673.7
Transmission	2,689.1	546.4	297.4	2,668.4	476.1	233.5
Generation	-	1,074.8	21.2	-	687.7	9.4
Total Property, Plant and Equipment, Gross	7,108.7	3,072.8	1,022.9	6,849.1	2,539.2	916.6
Less: Accumulated Depreciation	(1,596.7)	(893.6)	(240.5)	(1,508.7)	(837.3)	(228.5)
Property, Plant and Equipment, Net	5,512.0	2,179.2	782.4	5,340.4	1,701.9	688.1
Construction Work in Progress	315.4	77.5	295.4	246.1	351.4	129.0
Total Property, Plant and Equipment, Net	$ 5,827.4	$ 2,256.7	$ 1,077.8	$ 5,586.5	$ 2,053.3	$ 817.1

On May 31, 2011, CL&P completed the sale of a segment of high voltage transmission lines in the town of Wallingford, Connecticut. The assets were sold at their net book value of $42.5 million, plus reimbursement of closing costs. CL&P will operate and maintain the lines under an operations and maintenance agreement.

PSNH charges planned major maintenance activities to Operating Expenses unless the cost represents the acquisition of additional components.

CL&P, PSNH and WMECO have entered into certain equipment purchase contracts that require the Company to make advance payments during the design, manufacturing, shipment and installation of equipment. As of December 31, 2011 and 2010, advance payments totaling $15.2 million and $9.3 million, respectively ($1.3 million and $1.3 million for CL&P, zero and $4.9 million for PSNH and $13.9 million and $3.1 million for WMECO, respectively) are included in CWIP in the table above and are not subject to depreciation.

The following table summarizes average depreciable lives as of December 31, 2011:

	Average Depreciable Life			
(Years)	**NU**	**CL&P**	**PSNH**	**WMECO**
Distribution	38.8	42.1	33.9	29.6
Transmission	41.2	40.6	41.9	47.0
Generation	29.6	-	29.6	25.0
Other	17.7	-	-	-

The provision for depreciation on utility assets is calculated using the straight-line method based on the estimated remaining useful lives of depreciable plant in-service, adjusted for salvage value and removal costs, as approved by the appropriate regulatory agency (the PURA, NHPUC and the DPU for CL&P, PSNH and WMECO, respectively). Depreciation rates are applied to plant-in-service from the time it is placed in service. When a plant is retired from service, the original cost of the plant is charged to the accumulated provision for depreciation, which includes cost of removal less salvage. Cost of removal is classified as a Regulatory Liability on the accompanying consolidated balance sheets. The depreciation rates for the several classes of utility plant-in-service are equivalent to composite rates as follows:

(Percent)	**2011**	**2010**	**2009**
NU	2.6	2.7	2.9
CL&P	2.4	2.7	3.0
PSNH	2.9	2.8	2.7
WMECO	2.9	2.8	2.9

4.

DERIVATIVE INSTRUMENTS

The costs and benefits of derivative contracts that meet the definition of and are designated as normal purchases or normal sales (normal) are recognized in Operating Expenses or Operating Revenues on the accompanying consolidated statements of income, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not recorded as normal under the applicable accounting guidance are recorded at fair value as current or long-term derivative assets or liabilities. For the Regulated companies, regulatory assets or liabilities are recorded for the changes in fair values of derivatives, as these contracts are part of current regulated operating costs, or have an allowed recovery mechanism, and management believes that these costs will continue to be recovered from or refunded to customers in cost-of-service, regulated rates. Changes in fair values of NU's remaining unregulated wholesale marketing contracts are included in Net Income.

The Regulated companies are exposed to the volatility of the prices of energy and energy-related products in procuring energy supply for their customers. The costs associated with supplying energy to customers are recoverable through customer rates. The Company manages the risks associated with the price volatility of energy and energy-related products through the use of derivative contracts, many of which are accounted for as normal, and the use of nonderivative contracts.

CL&P and WMECO mitigate the risks associated with the price volatility of energy and energy-related products through the use of SS, LRS, and basic service contracts, which fix the price of electricity purchased for customers for periods of time ranging from three months to three years for CL&P and from three months to one year for WMECO and are accounted for as normal. CL&P has entered into derivatives, including FTR contracts, to manage the risk of congestion costs associated with its SS and LRS contracts. As required by regulation, CL&P has also entered into derivative and nonderivative contracts for the purchase of energy and energy-related products and contracts related to capacity and WMECO has entered into a contract to purchase renewable energy that is a derivative. While the risks managed by these contracts relate to regional congestion costs, capacity prices and the development of renewable energy, electric distribution companies, including CL&P and WMECO, are required to enter into these contracts. The costs or benefits from these contracts are recoverable from or refundable to customers, and, therefore changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying consolidated balance sheets.

PSNH mitigates the risks associated with the volatility of energy prices in procuring energy supply for its customers through its generation facilities and the use of derivative contracts, including energy forward contracts and FTRs. PSNH enters into these contracts in order to stabilize electricity prices for customers by mitigating uncertainties associated with the New England spot market. The costs or benefits from these contracts are recoverable from or refundable to PSNH's customers, and, therefore changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying consolidated balance sheets.

NU, through Select Energy, has one remaining fixed price forward sales contract to serve electrical load that is part of its remaining unregulated wholesale energy marketing portfolio. NU mitigates the price risk associated with this contract through the use of forward

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purchase contracts. The contracts are accounted for at fair value, and changes in their fair values are recorded in Fuel, Purchased and Net Interchange Power on the accompanying consolidated statements of income.

NU is also exposed to interest rate risk associated with its long-term debt. From time to time, various subsidiaries of the Company enter into forward starting interest rate swaps, accounted for as cash flow hedges, to mitigate the risk of changes in interest rates when they expect to issue long-term debt. NU parent has also entered into an interest rate swap on fixed rate long-term debt in order to balance its fixed and floating rate debt. This interest rate swap is accounted for as a fair value hedge.

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with current and long-term portions, in the accompanying consolidated balance sheets. Cash collateral posted or collected under master netting agreements is recorded as an offset to the derivative asset or liability. The following tables present the gross fair values of contracts and the net amounts recorded as current or long-term derivative assets or liabilities, by primary underlying risk exposures or purpose:

	As of December 31, 2011				
	Derivatives Not Designated as Hedges				
(Millions of Dollars)	Commodity and Capacity Contracts Required by Regulation	Commodity Supply and Price Risk Management	Hedging Instruments	Collateral and Netting (1)	Net Amount Recorded as Derivative Asset/(Liability) (2)
Current Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 2.3	$ -	$ 2.3
Level 3:					
CL&P	17.5	0.4	-	(11.6)	6.3
Other	-	4.7	-	-	4.7
Total Current Derivative Assets	$ 17.5	$ 5.1	$ 2.3	$ (11.6)	$ 13.3
Long-Term Derivative Assets:					
Level 3:					
CL&P	$ 174.2	$ -	$ -	$ (80.4)	$ 93.8
Other	-	4.6	-	-	4.6
Total Long-Term Derivative Assets	$ 174.2	$ 4.6	$ -	$ (80.4)	$ 98.4
Current Derivative Liabilities:					
Level 3:					
CL&P	$ (95.9)	$ -	$ -	$ -	$ (95.9)

WMECO		(0.1)		-		-		-		(0.1)
Other		-		(16.1)		-		4.5		(11.6)
Total Current Derivative Liabilities	$	(96.0)	$	(16.1)	$	-	$	4.5	$	(107.6)
<u>Long-Term Derivative Liabilities:</u>										
Level 3:										
CL&P	$	(935.8)	$	-	$	-	$	-	$	(935.8)
WMECO		(7.2)		-		-		-		(7.2)
Other		-		(17.3)		-		0.4		(16.9)
Total Long-Term Derivative Liabilities	$	(943.0)	$	(17.3)	$	-	$	0.4	$	(959.9)

	As of December 31, 2010				
	Derivatives Not Designated as Hedges				
(Millions of Dollars)	**Commodity and Capacity Contracts Required by Regulation**	**Commodity Supply and Price Risk Management**	**Hedging Instruments**	**Collateral and Netting (1)**	**Net Amount Recorded as Derivative Asset/(Liability) (2)**
Current Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 7.7	$ -	$ 7.7
Level 3:					
CL&P	5.8	2.1	-	-	7.9
Other	-	1.7	-	-	1.7
Total Current Derivative Assets	$ 5.8	$ 3.8	$ 7.7	$ -	$ 17.3
Long-Term Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 4.1	$ -	$ 4.1
Level 3:					
CL&P	195.9	-	-	(80.0)	115.9
Other	-	3.2	-	-	3.2
Total Long-Term Derivative Assets	$ 195.9	$ 3.2	$ 4.1	$ (80.0)	$ 123.2
Current Derivative Liabilities:					
Level 2:					
PSNH	$ -	$ (12.8)	$ -	$ -	$ (12.8)
Level 3:					
CL&P	(54.3)	(0.2)	-	7.7	(46.8)
Other	-	(12.4)	-	0.5	(11.9)
Total Current Derivative Liabilities	$ (54.3)	$ (25.4)	$ -	$ 8.2	$ (71.5)
Long-Term Derivative Liabilities:					
Level 3:					
CL&P	$ (883.1)	$ -	$ -	$ -	$ (883.1)
Other	-	(26.8)	-	0.2	(26.6)
Total Long-Term Derivative Liabilities	$ (883.1)	$ (26.8)	$ -	$ 0.2	$ (909.7)

(1)

Amounts represent cash collateral posted under master netting agreements and the netting of derivative assets and liabilities. See Credit Risk below for discussion of cash collateral posted under master netting agreements.

(2)

Current derivative assets are included in Prepayments and Other Current Assets on the accompanying consolidated balance sheets. WMECO derivative liabilities are included in Other Current Liabilities and Other Long-Term Liabilities on the accompanying consolidated balance sheets.

The business activities of the Company that resulted in the recognition of derivative assets also create exposure to various counterparties. As of December 31, 2011, NU and CL&P's derivative assets are exposed to counterparty credit risk. Of these amounts, $102.0 million and $99.7 million, respectively, is contracted with investment grade entities and the remainder is contracted with multiple other counterparties.

For further information on the fair value of derivative contracts, see Note 1I, Summary of Significant Accounting Policies - Fair Value Measurements, and Note 1J, Summary of Significant Accounting Policies Derivative Accounting, to the consolidated financial statements.

<u>Derivatives not designated as hedges</u>

Commodity and capacity contracts required by regulation: CL&P has capacity-related contracts with generation facilities. These contracts and similar UI contracts have an expected capacity of 787 MW. CL&P has a sharing agreement with UI, with 80 percent of each contract allocated to CL&P and 20 percent allocated to UI. The capacity contracts have terms up to 15 years and obligate the utilities to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set capacity price and the forward capacity market price received in the ISO-NE capacity markets. The largest of these generation facilities achieved commercial operation in July 2011. In addition, CL&P has a contract to purchase 0.1 million MWh of energy per year through 2020.

WMECO has a renewable energy contract to purchase 0.1 million MWh of energy per year through 2027 with a facility that is expected to achieve commercial operation by December 2012.

Commodity supply and price risk management: As of December 31, 2011 and 2010, CL&P had 0.6 million and 1.8 million MWh, respectively, remaining under FTRs that extend through December 2012 and require monthly payments or receipts.

PSNH has 0.3 million MWh remaining under FTRs as of December 31, 2011 and 2010 that extend through December 2012 and require monthly payments or receipts. PSNH had electricity procurement contracts with delivery dates through 2011 to purchase an aggregate amount of 0.4 million MWh of power as of December 31, 2010.

As of December 31, 2011 and 2010, NU had approximately 0.1 million and 0.3 million MWh, respectively, of supply volumes remaining in its unregulated wholesale portfolio when expected sales are compared with contracted supply, both of which extend through 2013.

The following table presents the realized and unrealized gains/(losses) associated with derivative contracts not designated as hedges:

		Amount of Gain/(Loss) Recognized on Derivative Instrument		
	Location of Gain or Loss Recognized on Derivative	**For the Years Ended December 31,**		
(Millions of Dollars)		**2011**	**2010**	**2009**
NU				
Commodity and Capacity Contracts				
Required by Regulation	Regulatory Assets/Liabilities	$ (158.1)	$ (74.0)	$ (99.9)
Commodity Supply and Price Risk				
Management	Regulatory Assets/Liabilities	(3.9)	(21.7)	(73.2)
Commodity Supply and Price Risk Management	Fuel, Purchased and Net Interchange Power	0.5	2.7	6.2
CL&P				
Commodity and Capacity Contracts				
Required by Regulation	Regulatory Assets/Liabilities	(150.8)	(74.0)	(99.9)
Commodity Supply and Price Risk				
Management	Regulatory Assets/Liabilities	(2.8)	(6.2)	(7.8)
PSNH				
Commodity Supply and Price Risk				

Management	Regulatory Assets/Liabilities	(1.0)	(15.0)	(62.6)
WMECO				
Commodity and Capacity Contracts				
Required by Regulation	Regulatory Assets/Liabilities	(7.3)	-	-

For the Regulated companies, monthly settlement amounts are recorded as receivables or payables and as Operating Revenues or Fuel, Purchased and Net Interchange Power on the accompanying consolidated financial statements. Regulatory Assets/Liabilities are established with no impact to Net Income.

Hedging instruments

Fair Value Hedge: To manage the balance of its fixed and floating rate debt, NU parent has a fixed to floating interest rate swap on its $263 million, fixed rate senior notes maturing on April 1, 2012. This interest rate swap qualifies and was designated as a fair value hedge and requires semi-annual cash settlements. The changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in Interest Expense on the accompanying consolidated statements of income. There was no ineffectiveness recorded for the years ended December 31, 2011, 2010 and 2009. The cumulative changes in fair values of the swap and the Long-Term Debt are recorded as a Derivative Asset/Liability and an adjustment to Long-Term Debt Current Portion. Interest Receivable is recorded as a reduction of Interest Expense and is included in Prepayments and Other Current Assets.

The realized and unrealized gains/(losses) related to changes in fair value of the swap and Long-Term Debt as well as pre-tax Interest Expense, are as follows:

	For the Years Ended December 31,					
	2011		2010		2009	
(Millions of Dollars)	**Swap**	**Hedged Debt**	**Swap**	**Hedged Debt**	**Swap**	**Hedged Debt**
Changes in Fair Value	$ 1.0	$ (1.0)	$ 9.5	$ (9.5)	$ 1.6	$ (1.6)
Interest Recorded in Net Income	-	10.5	-	10.9	-	9.1

Cash Flow Hedges: Cash flow hedges are recorded at fair value, and the changes in the fair value of the effective portion of those contracts are recognized in AOCI. When a cash flow hedge is settled, the settlement amount is recorded in AOCI and is amortized into Net Income over the term of the underlying debt instrument. Cash flow hedges also impact Net Income when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is improbable of occurring or when the transaction is settled. In 2011, PSNH and WMECO entered into cash flow hedges related to a portion of their respective planned debt issuances. PSNH entered into three forward starting swaps to fix the U.S. dollar LIBOR swap rate of 3.749 percent on $80 million of a planned $160 million long-term debt issuance, 2.804 percent on the remaining $80 million of the planned $160 million long-term debt issuance and 3.6 percent on $120 million of long-term debt to be issued to refinance outstanding PCRBs. In May 2011, PSNH settled the swap associated with the $120 million refinancing of PCRBs and a $2.9 million pre-tax reduction in AOCI is being amortized over the life of the debt. In September 2011, PSNH settled the two remaining swaps associated with the $160 million long-term debt issuance and a $15.3 million pre-tax reduction in AOCI is being amortized over the life of the debt. WMECO entered into a forward starting swap to fix the U.S. dollar LIBOR swap rate of 3.7624 percent associated with $50 million of a planned $100 million long-term debt issuance. In September 2011, WMECO settled the swap and a $6.9 million pre-tax reduction in AOCI is being amortized over the life of the debt.

The pre-tax impact of cash flow hedging instruments on AOCI is as follows:

(Millions of Dollars)	Gains/(Losses) Recognized on Derivative Instruments For the Year Ended December 31, 2011	Gains/(Losses) Reclassified from AOCI into Interest Expense For the Years Ended December 31, 2011	2010	2009
NU	$ (25.1)	$ (1.3)	$ (0.4)	$ (0.4)
CL&P	-	(0.7)	(0.7)	(0.7)
PSNH	(18.2)	(0.8)	(0.2)	(0.2)
WMECO	(6.9)	(0.1)	0.1	0.1

For further information, see Note 16, Accumulated Other Comprehensive Income/(Loss), to the consolidated financial statements.

Credit Risk

Certain derivative contracts that are accounted for at fair value, including NU's sourcing contracts related to the remaining wholesale marketing contract and PSNH's electricity procurement contracts, contain credit risk contingent features. These features require these companies to maintain investment grade credit ratings from the major rating agencies and to post cash or standby LOCs as collateral for contracts in a net liability position over specified credit limits. NU parent provides standby LOCs under its revolving credit agreement for NU subsidiaries to post with counterparties. The following summarizes the fair value of derivative contracts that are in a liability position and subject to credit risk contingent features, the fair value of cash collateral and standby LOCs posted with counterparties and the additional collateral in the form of LOCs that would be required to be posted by NU or PSNH if the respective unsecured debt credit ratings of NU parent or PSNH were downgraded to below investment grade as of December 31, 2011 and 2010:

	As of December 31, 2011			
(Millions of Dollars)	Fair Value Subject to Credit Risk Contingent Features	Cash Collateral Posted	Standby LOCs Posted	Additional Standby LOCs Required if Downgraded Below Investment Grade
NU	$ (23.5)	$ 4.1	$ -	$ 19.9

	As of December 31, 2010			
(Millions of Dollars)	Fair Value Subject to Credit Risk Contingent Features	Cash Collateral Posted	Standby LOCs Posted	Additional Standby LOCs Required if Downgraded Below Investment Grade
NU	$ (30.9)	$ 0.5	$ 24.0	$ 18.5

PSNH	(12.8)	-	24.0	-

Fair Value Measurements of Derivative Instruments:

Valuation of Derivative Instruments: Derivative contracts classified as Level 2 in the fair value hierarchy include Commodity Supply and Price Risk Management contracts and Interest Rate Risk Management contracts. Commodity Supply and Price Risk Management contracts include PSNH forward contracts to purchase energy for periods for which prices are quoted in an active market. Prices are obtained from broker quotes and based on actual market activity. The contracts are valued using the mid-point of the bid-ask spread. Valuations of these contracts also incorporate discount rates using the yield curve approach. Interest Rate Risk Management contracts represent interest rate swap agreements and are valued using a market approach provided by the swap counterparty using a discounted cash flow approach utilizing forward interest rate curves.

The derivative contracts classified as Level 3 in the tables below include the Regulated companies' Commodity and Capacity Contracts Required by Regulation, and Commodity Supply and Price Risk Management contracts (CL&P and PSNH FTRs and NU's remaining wholesale marketing portfolio). For Commodity and Capacity Contracts Required by Regulation and NU's remaining unregulated wholesale marketing portfolio, fair value is modeled using income techniques such as discounted cash flow approaches. Significant observable inputs for valuations of these contracts include energy and energy-related product prices for which quoted prices in an active market exist. Significant unobservable inputs used in the valuations of these contracts include energy and energy-related product prices for future years for long-dated Commodity and Capacity Contracts Required by Regulation and future contract quantities. 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 include assumptions regarding the timing and likelihood of scheduled payments and also reflect nonperformance risk, including credit, using the default probability approach based on the counterparty's credit rating for assets and the Company's credit rating for liabilities.

The remaining contracts included in Commodity Supply and Price Risk Management and classified as Level 3 in the tables below are valued using broker quotes based on prices in an inactive market.

Valuations using significant unobservable inputs: The following tables present changes for the years ended December 31, 2011 and 2010 in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis. The Company classifies assets and liabilities in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model. In addition to these unobservable inputs, the valuation models for Level 3 assets and liabilities typically also rely on a number of inputs that are observable either directly or indirectly. Thus the gains and losses presented below include changes in fair value that are attributable to both observable and

unobservable inputs. There were no transfers into or out of Level 3 assets and liabilities for the years ended December 31, 2011 and 2010.

	NU		
(Millions of Dollars)	Commodity and Capacity Contracts Required By Regulation	Commodity Supply and Price Risk Management	Total Level 3
Derivatives, Net:			
Fair Value as of January 1, 2010	$ (720.3)	$ (40.9)	$ (761.2)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income[1]	-	2.7	2.7
Regulatory Assets/Liabilities	(74.0)	(7.2)	(81.2)
Settlements	(13.7)	13.2	(0.5)
Fair Value as of December 31, 2010	$ (808.0)	$ (32.2)	$ (840.2)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income [1]	-	0.5	0.5
Regulatory Assets/Liabilities	(158.1)	(2.9)	(161.0)
Settlements	26.8	11.7	38.5
Fair Value as of December 31, 2011	$ (939.3)	$ (22.9)	$ (962.2)
Gains Included in Net Income Relating to Items Held as of End of Year:			
2011	-	0.7	0.7
2010	-	1.2	1.2

	CL&P			WMECO
(Millions of Dollars)	Commodity and Capacity Contracts Required By Regulation	Commodity Supply and Price Risk Management	Total Level 3	Commodity and Capacity Contracts Required By Regulation
Derivatives, Net:				
Fair Value as of January 1, 2010	$ (720.3)	$ 4.5	$ (715.8)	$ -
Net Realized/Unrealized Losses Included in:				
Regulatory Assets/Liabilities	(74.0)	(6.2)	(80.2)	-
Settlements	(13.7)	3.6	(10.1)	-
Fair Value as of December 31, 2010	$ (808.0)	$ 1.9	$ (806.1)	$ -
Net Realized/Unrealized Losses Included in:				
Regulatory Assets/Liabilities	(150.8)	(2.8)	(153.6)	(7.3)
Settlements	26.8	1.3	28.1	-
Fair Value as of December 31, 2011	$ (932.0)	$ 0.4	$ (931.6)	$ (7.3)

(1)

Gains and losses on derivatives included in Net Income relate to NU's remaining wholesale marketing contracts and are reported in Fuel, Purchased and Net Interchange Power on the accompanying consolidated statements of income.

5.

MARKETABLE SECURITIES (NU, WMECO)

NU maintains a supplemental benefit trust to fund NU s SERP and non-SERP obligations and WMECO maintains a spent nuclear fuel trust to fund WMECO s prior period spent nuclear fuel liability, both of which hold marketable securities. These trusts are not subject to regulatory oversight by state or federal agencies.

The Company elects to record mutual funds purchased by the NU supplemental benefit trust at fair value. As such, any change in fair value of these purchased equity securities is reflected in Net Income. These equity securities, classified as Level 1 in the fair value hierarchy, totaled $41.1 million and $42.2 million as of December 31, 2011 and 2010, respectively, and are included in current Marketable Securities. Losses on these securities of $1.1 million and gains of $6.9 million for the years ended December 31, 2011 and 2010, respectively, were recorded in Other Income, Net on the accompanying consolidated statements of income. Dividend income is recorded when dividends are declared and are recorded in Other Income, Net on the accompanying consolidated statements of income. All other marketable securities are accounted for as available-for-sale.

Available-for-Sale Securities: The following is a summary of NU's available-for-sale securities held in the NU supplemental benefit trust and WMECO's spent nuclear fuel trust. These securities are recorded at fair value and included in current and long-term Marketable Securities on the accompanying consolidated balance sheets.

	As of December 31, 2011			
(Millions of Dollars)	Amortized Cost	Pre-Tax Unrealized Gains(1)	Pre-Tax Unrealized Losses(1)	Fair Value
NU	$ 88.4	$ 2.0	$ (0.2)	$ 90.2
WMECO	57.3	-	(0.2)	57.1

	As of December 31, 2010			
(Millions of Dollars)	Amortized Cost	Pre-Tax Unrealized Gains(1)	Pre-Tax Unrealized Losses(1)	Fair Value
NU	$ 86.3	$ 1.3	$ (0.3)	$ 87.3
WMECO	57.2	-	(0.1)	57.1

(1)

Unrealized gains and losses on debt securities for the NU supplemental benefit trust and WMECO spent nuclear fuel trust are recorded in AOCI and Other Long-Term Assets, respectively, on the accompanying consolidated balance sheets.

Unrealized Losses and Other-than-Temporary Impairment: There have been no significant unrealized losses, other-than-temporary impairments or credit losses for the NU supplemental benefit trust or WMECO spent nuclear fuel trust. Factors considered in determining whether a credit loss exists include the duration and severity of the impairment, adverse conditions specifically affecting the issuer, and the payment history, ratings and rating changes of the security. For asset-backed debt securities, underlying collateral and expected future cash flows are also evaluated.

Realized Gains and Losses: Realized gains and losses on available-for-sale-securities, including any credit loss and any gains or losses on securities the company intends to sell or will be required to sell, are recorded in Other Income, Net for the NU supplemental benefit trust and in Other Long-Term Assets for the WMECO spent nuclear fuel trust. NU utilizes the specific identification basis method for the NU supplemental benefit trust securities and the average cost basis method for the WMECO spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities.

Contractual Maturities: As of December 31, 2011, the contractual maturities of available-for-sale debt securities are as follows:

	NU				WMECO			
(Millions of Dollars)	**Amortized Cost**		**Fair Value**		**Amortized Cost**		**Fair Value**	
Less than one year	$	29.9	$	29.9	$	26.4	$	26.3
One to five years		25.4		25.6		20.7		20.7
Six to ten years		10.9		11.3		6.1		6.1
Greater than ten years		22.2		23.4		4.1		4.0
Total Debt Securities	$	88.4	$	90.2	$	57.3	$	57.1

Fair Value Measurements: The following table presents the marketable securities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	NU As of December 31,				WMECO As of December 31,			
(Millions of Dollars)	**2011**		**2010**		**2011**		**2010**	
Level 1:								
Mutual Funds	$	41.1	$	42.2	$	-	$	-
Money Market Funds		1.8		1.8		0.1		0.3
Total Level 1	$	42.9	$	44.0	$	0.1	$	0.3
Level 2:								
U.S. Government Issued Debt Securities (Agency and Treasury)		11.1		17.8		8.0		6.0
Corporate Debt Securities		16.5		22.5		9.1		15.6
Asset-Backed Debt Securities		25.9		11.6		7.9		4.7
Municipal Bonds		16.1		16.1		15.4		15.4
Other Fixed Income Securities		18.8		17.5		16.6		15.1
Total Level 2	$	88.4	$	85.5	$	57.0	$	56.8
Total Marketable Securities	$	131.3	$	129.5	$	57.1	$	57.1

U.S. government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instrument and also incorporating yield curves, credit spreads and specific bond terms and conditions. Asset-backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset-backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and maturity dates and tranche information. Municipal bonds are valued using a market approach that incorporates reported trades and benchmark yields. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

6.

ASSET RETIREMENT OBLIGATIONS

In accordance with accounting guidance for conditional AROs, NU, including CL&P, PSNH and WMECO, recognizes a liability for the fair value of an ARO on the obligation date if the liability's fair value can be reasonably estimated and is conditional on a future event. Settlement dates and future costs are reasonably estimated when sufficient information becomes available. Management has identified various categories of AROs, primarily certain assets containing asbestos and hazardous contamination and has performed fair value calculations, reflecting expected probabilities for settlement scenarios.

The fair value of an ARO is recorded as a liability in Other Long-Term Liabilities with an offset included in Property, Plant and Equipment, Net on the accompanying consolidated balance sheets. As the Regulated companies are rate-regulated on a cost-of-service basis, these companies apply regulatory accounting guidance and the costs associated with the Regulated companies' AROs are included in Other Regulatory Assets as of December 31, 2011 and 2010. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively. Both the depreciation and accretion were recorded as increases to Regulatory Assets on the accompanying consolidated balance sheets as of December 31, 2011 and 2010. For further information, see Note 2, Regulatory Accounting, to the consolidated financial statements.

A reconciliation of the beginning and ending carrying amounts of Regulated companies' ARO liabilities are as follows:

NU	**As of December 31,**	
(Millions of Dollars)	**2011**	**2010**
Balance as of Beginning of Year	$ 53.3	$ 50.6
Liabilities Incurred During the Year	2.1	0.2
Liabilities Settled During the Year	(0.8)	(1.2)
Accretion	3.5	3.3
Revisions in Estimated Cash Flows	(1.9)	0.4
Balance as of End of Year	$ 56.2	$ 53.3

	As of December 31,					
	2011			**2010**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Balance as of Beginning of Year	$ 29.3	$ 17.6	$ 3.6	$ 28.6	$ 16.4	$ 3.3

Liabilities Incurred During the Year		1.7		0.2		0.2		0.1		-		0.1
Liabilities Settled During the Year		(0.8)		-		-		(1.2)		-		-
Accretion		2.0		1.1		0.2		1.8		1.1		0.2
Revisions in Estimated Cash Flows		-		(1.9)		-		-		0.1		-
Balance as of End of Year	$	32.2	$	17.0	$	4.0	$	29.3	$	17.6	$	3.6

7.

GOODWILL (NU)

Goodwill and intangible assets deemed to have indefinite useful lives are reviewed for impairment at least annually by applying a fair value-based test. NU uses October 1st as the annual goodwill impairment testing date. However, if an event occurs or circumstances change that would indicate that goodwill might be impaired, NU management would test the goodwill between the annual testing dates. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount.

NU's reporting units are consistent with the operating segments underlying the reportable segments identified in Note 21, Segment Information, to the consolidated financial statements. The only reporting unit that maintains goodwill is the Yankee Gas reporting unit, which is classified under the Regulated companies natural gas reportable segment and related to the acquisition of Yankee Energy System, Inc., parent of Yankee Gas. Such goodwill is not being recovered from the customers of Yankee Gas. The goodwill balance held by the Yankee Gas reporting unit as of December 31, 2011 and 2010 is $287.6 million.

NU completed its impairment analysis of the Yankee Gas goodwill balance as of October 1, 2011 and determined that no impairment exists. In completing this analysis, the fair value of the reporting unit was estimated using a discounted cash flow methodology and analyses of comparable companies and transactions.

8.

SHORT-TERM DEBT

Limits: The amount of short-term borrowings that may be incurred by CL&P and WMECO is subject to periodic approval by the FERC. As a result of the NHPUC having jurisdiction over PSNH's short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings. On November 30, 2011, the FERC granted authorization to allow CL&P and WMECO to incur total short-term borrowings up to a maximum of $450 million and $300 million, respectively, effective January 1, 2012 through December 31, 2013.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant. In an order dated December 17, 2010, the NHPUC increased the amount of short-term borrowings authorized for PSNH to a maximum of 10 percent of net fixed plant plus an additional $60 million until further ordered by the NHPUC. As of December 31, 2011, PSNH's short-term debt authorization under the 10 percent of net fixed plant test plus $60 million totaled approximately $270 million.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur, including limiting unsecured indebtedness with a maturity of less than 10 years to 10 percent of total capitalization. In November 2003, CL&P obtained from its preferred stockholders a waiver of such 10 percent limit for a ten-year period expiring in March 2014, provided that all unsecured indebtedness does not exceed 20 percent of total capitalization. As of December 31, 2011, CL&P had $826.3 million of unsecured debt capacity available under this authorization.

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

CL&P, PSNH, WMECO and Yankee Gas Credit Agreement: On September 24, 2010, CL&P, PSNH, WMECO and Yankee Gas jointly entered into a three-year unsecured revolving credit facility in the amount of $400 million, which terminates on September 24, 2013. CL&P and PSNH may borrow up to $300 million each under this facility, with WMECO and Yankee Gas able to borrow up to $200 million each, subject to the $400 million maximum aggregate borrowing limit. This total commitment may be increased to $500 million at the request of the borrowers, subject to lender approval. Under this facility, each company can borrow either on a short-term or a long-term basis subject to regulatory approval. As of December 31, 2011, CL&P and Yankee Gas had $31 million and $30 million, respectively, in short-term borrowings outstanding under this credit facility. The weighted average interest rate on such borrowings outstanding under this credit facility as of December 31, 2011 was 4.03 percent and 2.07 percent, respectively. There were no borrowings outstanding by PSNH and WMECO under this facility as of December 31, 2011**.** As of December 31, 2010, PSNH had $30 million in short-term borrowings outstanding under this credit facility. The weighted average interest rate on such borrowings outstanding under this credit facility as of December 31, 2010 was 2.05 percent. There were no borrowings outstanding by CL&P, WMECO and Yankee Gas under this facility as of December 31, 2010.

NU Parent Credit Agreement: On September 24, 2010, NU parent entered into a three-year unsecured revolving credit facility in the amount of $500 million, which terminates on September 24, 2013. Subject to the amount of advances outstanding, LOCs can be issued under this facility for periods up to 364 days on the account of NU parent or any of its subsidiaries up to the total amount of the facility. This total commitment may be increased to $600 million at the request of NU parent, subject to lender approval. Under this facility, NU parent can borrow either on a short-term or a long-term basis. As of December 31, 2011 and 2010, NU parent had $256 million and $237 million, respectively, in short-term borrowings outstanding under this facility. The weighted-average interest rate on such borrowings outstanding under this credit facility as of December 31, 2011 and 2010 was 2.20 percent and 2.85 percent, respectively. There were $17.9 million, $4 million and $5.4 million in LOCs outstanding as of December 31, 2011 for NU, CL&P and PSNH, respectively. There were $32.1 million and $30.1 million in LOCs outstanding as of December 31, 2010 for NU and PSNH, respectively.

Under these credit facilities, NU parent and CL&P, PSNH, WMECO and Yankee Gas may borrow at prime rates or LIBOR-based rates, plus an applicable margin based upon the higher of S&P's or Moody's credit ratings assigned to the borrower.

In addition, NU parent, CL&P, PSNH, WMECO and Yankee Gas must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. NU parent, CL&P, PSNH, WMECO and Yankee Gas were in compliance with these covenants as of December 31, 2011. If NU parent or CL&P, PSNH, WMECO or Yankee Gas were not in compliance with these covenants, an event of default would occur requiring all outstanding borrowings by such borrower to be repaid and additional borrowings by such borrower would not be permitted under the respective credit facility.

Amounts outstanding under these credit facilities are classified as current liabilities as Notes Payable to Banks on the accompanying consolidated balance sheets, as management anticipates that all borrowings under these credit facilities will be outstanding for no more than 364 days at one time.

Money Pool: NU parent, CL&P, PSNH, WMECO, Yankee Gas and certain of NU's other subsidiaries are members of the Money Pool. The Money Pool provides an efficient use of cash resources of NU and reduces outside short-term borrowings. NUSCO participates in the Money Pool and administers the Money Pool as agent for the member companies. Short-term borrowing needs of the member companies are met with available funds of other member companies, including funds borrowed by NU parent. NU parent may lend to the Money Pool but may not borrow. Funds may be withdrawn from or repaid to the Money Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on external loans of NU, however, accrue interest at NU's cost and are payable on demand. In NU's consolidated financial statements, Money Pool amounts payable to or receivable from members eliminate in consolidation. By order, the FERC has exempted all holding company system money pools from active regulation. As of December 31, 2011 and 2010, CL&P, PSNH and WMECO had the following borrowings from/(lendings to) the Money Pool with the respective weighted-average interest rate on borrowings from the Money Pool:

	As of and for the Years Ended December 31,					
	2011			**2010**		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Borrowings from/(Lendings to)	$ 58.5	$ (55.9)	$ (11.0)	$ 6.2	$ 47.9	$ 20.4
Weighted-Average Interest Rates	0.08%	0.1 %	0.1 %	0.19%	0.18%	0.14%

The net borrowings from/(lendings to) the Money Pool are recorded in Notes Payable to/Notes Receivable from Affiliated Companies on the accompanying consolidated balance sheets, respectively.

9.

LONG-TERM DEBT

Details of long-term debt outstanding for NU, including CL&P, PSNH and WMECO are as follows:

CL&P		**As of December 31,**		
(Millions of Dollars)		**2011**		**2010**
First Mortgage Bonds:				
7.875% 1994 Series D due 2024	$	139.8	$	139.8
4.800% 2004 Series A due 2014		150.0		150.0
5.750% 2004 Series B due 2034		130.0		130.0
5.000% 2005 Series A due 2015		100.0		100.0
5.625% 2005 Series B due 2035		100.0		100.0
6.350% 2006 Series A due 2036		250.0		250.0
5.375% 2007 Series A due 2017		150.0		150.0
5.750% 2007 Series B due 2037		150.0		150.0
5.750% 2007 Series C due 2017		100.0		100.0
6.375% 2007 Series D due 2037		100.0		100.0
5.650% 2008 Series A due 2018		300.0		300.0
5.500% 2009 Series A due 2019		250.0		250.0
Total First Mortgage Bonds		1,919.8		1,919.8
Pollution Control Notes:				
5.85%-5.90% Tax Exempt Fixed Rate due 2016-2022		46.4		46.4
5.85% Fixed Rate Tax Exempt due 2028 (1)		-		245.5
5.95% Fixed Rate Tax Exempt due 2028		70.0		70.0
4.375% Fixed Rate Tax Exempt due 2028 (1)		120.5		-
1.25% Fixed Rate Tax Exempt due 2028 (1)		125.0		-
One-Year Fixed Rate Tax Exempt due 2031(2)		62.0		62.0
Total Pollution Control Notes		423.9		423.9
Total First Mortgage Bonds and Pollution Control Notes		2,343.7		2,343.7
Fees and Interest due for Spent Nuclear Fuel Disposal Costs		244.1		243.8
Less Amounts due Within One Year(2)		(62.0)		(62.0)
Unamortized Premiums and Discounts, Net		(4.0)		(4.4)
CL&P Long-Term Debt	$	2,521.8	$	2,521.1

PSNH		**As of December 31,**		
(Millions of Dollars)		**2011**		**2010**
First Mortgage Bonds:				
5.25% 2004 Series L due 2014	$	50.0	$	50.0
5.60% 2005 Series M due 2035		50.0		50.0
6.15% 2007 Series N due 2017		70.0		70.0
6.00% 2008 Series O due 2018		110.0		110.0
4.50% 2009 Series P due 2019		150.0		150.0
4.05% 2011 Series Q due 2021(3)		122.0		-

3.20% 2011 Series R due 2021		160.0		-
Total First Mortgage Bonds		712.0		430.0
Pollution Control Revenue Bonds:				
4.75%- 5.45% Tax Exempt Series B and C due 2021		198.2		198.2
6.00% Tax Exempt Series D and E due 2021[3]		-		119.8
Adjustable Rate Series A due 2021		89.3		89.3
Total Pollution Control Revenue Bonds		287.5		407.3
Unamortized Premiums and Discounts, Net		(1.8)		(0.9)
PSNH Long-Term Debt	$	997.7	$	836.4

WMECO		As of December 31,		
(Millions of Dollars)		**2011**		**2010**
Pollution Control and Other Notes:				
Tax Exempt 1993 Series A, 5.85% due 2028	$	53.8	$	53.8
Senior Notes Series A, 5.00% due 2013		55.0		55.0
Senior Notes Series B, 5.90% due 2034		50.0		50.0
Senior Notes Series C, 5.24% due 2015		50.0		50.0
Senior Notes Series D, 6.70% due 2037		40.0		40.0
Senior Notes Series E, 5.10% due 2020		95.0		95.0
Senior Notes Series F, 3.50% due 2021		100.0		-
Total Pollution Control Notes and Other Notes		443.8		343.8
Fees and Interest due for Spent Nuclear Fuel Disposal Costs		57.3		57.2
Unamortized Premiums and Discounts, Net		(1.6)		(0.7)
WMECO Long-Term Debt	$	499.5	$	400.3

OTHER		As of December 31,		
(Millions of Dollars)		**2011**		**2010**
Yankee Gas - First Mortgage Bonds:				
8.48% Series B due 2022	$	20.0	$	20.0
7.19% Series E due 2012		4.3		8.6
4.80% Series G due 2014		75.0		75.0
5.26% Series H due 2019		50.0		50.0
5.35% Series I due 2035		50.0		50.0
6.90% Series J due 2018		100.0		100.0
4.87% Series K due 2020		50.0		50.0
Total First Mortgage Bonds		349.3		353.6
Less Amounts due Within One Year		(4.3)		(4.3)
Unamortized Premiums and Discounts, Net		0.9		1.0
Total First Mortgage Bonds		345.9		350.3
NU Parent - Notes:				
7.25% Senior Notes Series A due 2012		263.0		263.0
5.65% Senior Notes Series C due 2013		250.0		250.0
Total NU Parent - Notes		513.0		513.0
Less Amounts due Within One Year		(265.3)		-
Fair Value Adjustment		2.3		11.8
Other Long-Term Debt		595.9		875.1
Total NU Long-Term Debt	$	4,614.9	$	4,632.9

(1)

On October 24, 2011, CL&P issued $120.5 million of tax-exempt PCRBs carrying a coupon of 4.375 percent that mature on September 1, 2028 and issued $125 million of tax-exempt PCRBs carrying a coupon of 1.25 percent that mature on September 1, 2028 and are subject to mandatory tender for purchase on September 3, 2013. The $125 million of tax-exempt PCRBs were issued with an initial fixed rate term period ending on September 2, 2013, at which time CL&P expects to remarket the PCRBs. The proceeds from these two CL&P issuances were used to refund

$245.5 million of PCRBs that carried a coupon of 5.85 percent and had a maturity date of September 1, 2028.

(2)

On April 1, 2011, CL&P remarketed the $62 million of tax-exempt PCRBs for a one-year period. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.25 percent during the current one-year fixed-rate period and are subject to mandatory tender for purchase on April 1, 2012, at which time CL&P expects to remarket the bonds.

(3)

On May 26, 2011, PSNH issued $122 million of first mortgage bonds with a coupon rate of 4.05 percent and a maturity date of June 1, 2021, and used the proceeds to redeem $119.8 million of its tax-exempt 1992 Series D and 1993 Series E PCRBs, each with a maturity date of May 1, 2021 and a coupon rate of 6 percent.

Long-term debt maturities and cash sinking fund requirements on debt outstanding as of December 31, 2011 for the years 2012 through 2016 and thereafter, are shown below. These amounts exclude fees and interest due for spent nuclear fuel disposal costs, net unamortized premiums and discounts and other fair value adjustments as of December 31, 2011:

(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**
2012	$ 329.3	$ 62.0	$ -	$ -
2013	430.0	125.0	-	55.0
2014	275.0	150.0	50.0	-
2015	150.0	100.0	-	50.0
2016	15.4	15.4	-	-
Thereafter	3,449.6	1,891.3	949.5	338.8
Total	$ 4,649.3	$ 2,343.7	$ 999.5	$ 443.8

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

The CL&P, PSNH and WMECO tax-exempt bonds contain call provisions providing call prices ranging between 100 percent and 102 percent of par. All other long-term debt securities are subject to make-whole provisions.

As of December 31, 2011, CL&P had $423.9 million of tax-exempt PCRBs outstanding, $70 million of which is secured by second mortgage liens on transmission assets, junior to the liens of its first mortgage bond indenture. CL&P has $307.5 million of tax-exempt PCRBs secured by first mortgage bonds. If CL&P failed to meet its obligations under the PCRBs, then these first mortgage bonds would become outstanding.

As of December 31, 2011, PSNH had $287.5 million in PCRBs outstanding. PSNH's obligation to repay each series of PCRBs is secured by first mortgage bonds and bond insurance. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. If PSNH failed to meet its obligations under the PCRBs, then these first mortgage bonds would become outstanding. The 2001 Series A PCRBs, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. The Company is not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agent. The weighted average effective interest rate on PSNH's Series A variable-rate PCRBs was 0.21 percent in 2011 and 0.34 percent in 2010.

NU's, including CL&P, PSNH and WMECO, long-term debt agreements provide that NU and certain of its subsidiaries must comply with certain financial and non-financial covenants as are customarily included in such agreements, including a consolidated debt to total capitalization ratio. NU and these subsidiaries were in compliance with these covenants as of December 31, 2011.

Yankee Gas has certain long-term debt agreements that contain cross-default provisions applicable to all of Yankee Gas outstanding first mortgage bond series. The cross-default provisions on Yankee Gas Series B Bonds would be triggered if Yankee Gas were to default on a payment due on indebtedness in excess of $2 million. The cross-default provisions on all other series of Yankee Gas first mortgage bonds would be triggered if Yankee Gas were to default in a payment due on indebtedness in excess of $10 million. No debt issuances of CL&P, PSNH, WMECO or NU parent contain cross-default provisions as of December 31, 2011.

The fair value adjustment relates to the NU parent 7.25 percent note, due 2012 in the amount of $263 million, that is hedged with a fixed to floating interest rate swap. The change in fair value of the interest component of the debt was recorded as an adjustment to Long-Term Debt (Long-Term Debt - Current Portion as of December 31, 2011 since the note was due within one year) with an equal and offsetting adjustment to Derivative Assets for the change in fair value of the fixed to floating interest rate swap.

Spent Nuclear Fuel Obligation: Under the Nuclear Waste Policy Act of 1982, CL&P and WMECO must pay the DOE for the costs of disposal of spent nuclear fuel and high-level radioactive waste for the period prior to the sale of their ownership shares in the Millstone nuclear power stations.

The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Spent Nuclear Fuel) for CL&P and WMECO, an accrual has been recorded for the full liability, and payment must be made by CL&P and WMECO to the DOE prior to the first delivery of spent fuel to the DOE. After the sale of Millstone, CL&P and WMECO remained responsible for their share of the disposal costs associated with the Prior Period Spent Nuclear Fuel. Until such payment to the DOE is made, the outstanding liability will continue to accrue interest at the 3-month Treasury bill yield rate. Fees due to the DOE for the disposal of Prior Period Spent Nuclear Fuel as of December 31, 2011 and 2010 are included in Long-Term Debt, including accumulated interest costs of $219.3 million and $218.9 million ($177.6 million and $177.3 million for CL&P and $41.7 million and $41.6 million for WMECO), respectively.

WMECO maintains a trust that holds marketable securities to fund amounts due to the DOE for the disposal of WMECO's Prior Period Spent Nuclear Fuel. For further information on this trust, see Note 5, Marketable Securities, to the consolidated financial statements.

10.

EMPLOYEE BENEFITS

A.

Pension Benefits and Postretirement Benefits Other Than Pensions

Pursuant to GAAP, NU is required to record the funded status of its Pension and PBOP Plans on the accompanying consolidated balance sheets, based on the difference between the projected benefit obligation for the Pension Plan and accumulated postretirement benefit obligation for the PBOP Plans and the fair value of plan assets measured in accordance with fair value measurement accounting guidance. Pursuant to GAAP, the funded status of pension and PBOP plans is recorded with an offset to Accumulated Other Comprehensive Income/(Loss). This amount is remeasured annually, or as circumstances dictate.

Charges for the Regulated companies are recorded as Regulatory Assets and included as deferred benefit costs as these benefits expense amounts have been and continue to be recoverable in cost-of-service, regulated rates. Regulatory accounting was also applied to the portions of the NUSCO costs that support the Regulated companies, as these amounts are also recoverable through rates charged to customers. Charges for the unregulated companies are recorded on an after-tax basis to Accumulated Other Comprehensive Income/(Loss). For further information see Note 2, Regulatory Accounting, and Note 16, Accumulated Other Comprehensive Income/(Loss), to the consolidated financial statements.

Pension Benefits: NUSCO sponsors a Pension Plan, which is subject to the provisions of ERISA, as amended by the PPA of 2006. The Pension Plan covers nonbargaining unit employees (and bargaining unit employees, as negotiated) of NU, including CL&P, PSNH, and WMECO, hired before 2006 (or as negotiated, for bargaining unit employees). Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. NU allocates net periodic pension expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked by the trustee for each subsidiary. The actual investment return for the trust each year is allocated to each of the subsidiaries in proportion to the investment return expected to be earned during the year. NU uses a December 31st measurement date for the Pension Plan.

In addition, NU has maintained a SERP since 1987. The SERP provides its eligible participants, who are officers of NU, with benefits that would have been provided to them under the Pension Plan if certain Internal Revenue Code limitations were not imposed. NU allocates net periodic SERP benefit costs to its subsidiaries based upon actuarial calculations by participant.

Although the Company maintains a trust to support the SERP with marketable securities held in the NU supplemental benefit trust, the plan itself does not contain any assets. For information regarding the investments in the NU supplemental benefit trust that are used to support the SERP liability, see Note 5, Marketable Securities, to the consolidated financial statements.

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

NU annually funds postretirement costs through external trusts with amounts that have been and will continue to be recovered in rates and that are tax deductible.

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

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

The expected return on plan assets is calculated by applying the assumed rate of return to a four-year rolling average of plan asset fair values, which reduces year-to-year volatility. This calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the calculated expected return and the actual return based on the change in the fair value of assets during the year. As investment gains and losses are reflected in the average plan asset fair values, they are subject to amortization with other unrecognized gains/losses. Unrecognized gains/losses are amortized as a component of pension and PBOP expense over the estimated average future service period of the employees of approximately 10 and 9 years, respectively.

The following tables represent information on NU's plan benefit obligations, fair values of plan assets, and funded status. Amounts related to the SERP obligation and expense are included with the Pension Plan in the tables below:

	Pension and SERP Benefits							
	As of December 31, 2011				As of December 31, 2010			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Change in Benefit Obligation								
Benefit Obligation as of Beginning of Year	$ (2,820.9)	$ (964.3)	$ (448.7)	$ (196.6)	$ (2,610.3)	$ (899.2)	$ (412.1)	$ (184.3)
Service Cost	(55.4)	(19.5)	(10.6)	(3.9)	(51.0)	(17.6)	(10.0)	(3.5)
Interest Cost	(153.3)	(51.9)	(24.4)	(10.7)	(152.6)	(52.2)	(24.1)	(10.7)
Actuarial Loss	(206.1)	(64.0)	(33.2)	(15.4)	(140.6)	(49.7)	(20.7)	(8.4)
Benefits Paid - Excluding Lump Sum Payments	134.4	55.6	18.9	10.8	130.2	54.1	18.1	10.3
Benefits Paid - SERP	2.4	0.3	0.1	-	2.5	0.3	0.1	-
Benefits Paid - Lump Sum Payments	-	-	-	-	0.9	-	-	-
Benefit Obligation as of End of Year	$ (3,098.9)	$ (1,043.8)	$ (497.9)	$ (215.8)	$ (2,820.9)	$ (964.3)	$ (448.7)	$ (196.6)
Change in Pension Plan Assets								
Fair Value of Plan Assets as of Beginning of Year	$ 1,977.6	$ 918.4	$ 185.4	$ 209.8	$ 1,789.6	$ 844.5	$ 137.1	$ 190.8
Actual Return on Plan Assets	19.1	6.8	0.6	3.0	274.1	128.0	21.4	29.3
Employer Contribution	143.6	-	112.6	-	45.0	-	45.0	-
Benefits Paid - Excluding Lump Sum Payments	(134.4)	(55.6)	(18.9)	(10.8)	(130.2)	(54.1)	(18.1)	(10.3)
Benefits Paid - Lump Sum Payments	-	-	-	-	(0.9)	-	-	-
Fair Value of Plan Assets as of End of Year	$ 2,005.9	$ 869.6	$ 279.7	$ 202.0	$ 1,977.6	$ 918.4	$ 185.4	$ 209.8
	$ (1,093.0)	$ (174.2)	$ (218.2)	$ (13.8)	$ (843.3)	$ (45.9)	$ (263.3)	$ 13.2

Funded Status as of December 31st

	PBOP Benefits							
	As of December 31, 2011				As of December 31, 2010			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Change in Benefit Obligation								
Benefit Obligation as of Beginning of Year	$ (489.9)	$ (190.2)	$ (89.9)	$ (41.7)	$ (475.7)	$ (188.1)	$ (87.5)	$ (41.0)
Service Cost	(9.2)	(2.9)	(1.9)	(0.6)	(8.5)	(2.7)	(1.8)	(0.6)
Interest Cost	(25.7)	(10.0)	(4.8)	(2.2)	(26.8)	(10.5)	(5.0)	(2.3)
Actuarial Loss	(30.1)	(8.5)	(8.4)	(1.0)	(17.5)	(4.3)	(1.5)	(1.0)
Federal Subsidy on Benefits Paid	(4.1)	(1.8)	(0.7)	(0.4)	(3.7)	(1.6)	(0.6)	(0.3)
Benefits Paid	38.1	14.5	6.5	3.0	42.3	17.0	6.5	3.5
Benefit Obligation as of End of Year	$ (520.9)	$ (198.9)	$ (99.2)	$ (42.9)	$ (489.9)	$ (190.2)	$ (89.9)	$ (41.7)
Change in Plan Assets								
Fair Value of Plan Assets as of Beginning of Year	$ 278.5	$ 108.6	$ 56.9	$ 26.7	$ 240.3	$ 93.2	$ 47.7	$ 23.6
Actual Return on Plan Assets	(2.5)	(1.2)	(0.4)	(0.1)	34.9	13.8	7.0	3.4
Employer Contribution	47.5	19.3	8.7	3.5	45.6	18.6	8.7	3.2
Benefits Paid	(38.1)	(14.5)	(6.5)	(3.0)	(42.3)	(17.0)	(6.5)	(3.5)
Fair Value of Plan Assets as of End of Year	$ 285.4	$ 112.2	$ 58.7	$ 27.1	$ 278.5	$ 108.6	$ 56.9	$ 26.7
Funded Status as of December 31st	$ (235.5)	$ (86.7)	$ (40.5)	$ (15.8)	$ (211.4)	$ (81.6)	$ (33.0)	$ (15.0)

Pension and SERP benefits funded status includes the current portion of the SERP liability, which is included in Other Current Liabilities on the accompanying consolidated balance sheets.

The accumulated benefit obligation for the Pension Plan as of December 31, 2011 and 2010 is as follows:

	Pension and SERP Benefits	
(Millions of Dollars)	**2011**	**2010**
NU	$ 2,810.6	$ 2,551.1
CL&P	938.4	868.3
PSNH	444.8	397.9

WMECO	195.5	177.4

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

	As of December 31,			
	Pension and SERP Benefits		PBOP Benefits	
	2011	**2010**	**2011**	**2010**
Discount Rate	5.03%	5.57%	4.84%	5.28%
Compensation/Progression Rate	3.50%	3.50%	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	7.00%	7.00%

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and OCI as well as amounts in Regulatory Assets and OCI reclassified as net periodic benefit (expense)/income during the years presented:

	Amount Reclassified To/From			
	Regulatory Assets		OCI	
	For the Years Ended December 31,			
(Millions of Dollars)	**2011**	**2010**	**2011**	**2010**
Pension and SERP				
Actuarial Losses Reclassified as Net Periodic Benefit Expense	$ (79.4)	$ (51.0)	$ (4.8)	$ (2.7)
Actuarial Losses Arising During the Year	334.8	45.3	23.0	3.7
Prior Service Cost Reclassified as Net Periodic Benefit Expense	(9.4)	(9.5)	(0.3)	(0.3)
PBOP				
Actuarial Losses Reclassified as Net Periodic Benefit Expense	$ (18.1)	$ (15.9)	$ (0.9)	$ (0.8)
Actuarial Losses Arising During the Year	50.2	4.2	4.0	0.7
Prior Service Credit Reclassified as Net Periodic Benefit Income	0.3	0.3	-	-
Transition Obligation Reclassified as Net Periodic Benefit Expense	(11.3)	(11.3)	(0.2)	(0.2)

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Loss amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2011 and 2010, and the amounts that are expected to be recognized as components in 2012:

	Regulatory Assets as of December 31,			AOCI as of December 31,		
(Millions of Dollars)	**2011**	**2010**	**Expected 2012 Expense**	**2011**	**2010**	**Expected 2012 Expense**
Pension and SERP						
Actuarial Loss	$ 1,126.1	$ 871.2	$ 113.4	$ 70.2	$ 51.9	$ 7.0
Prior Service Cost	29.3	38.8	8.1	1.4	1.7	0.3
PBOP						
Actuarial Loss	$ 196.3	$ 164.2	$ 20.6	$ 12.1	$ 9.0	$ 1.2
Prior Service Credit	(2.4)	(2.7)	(0.3)	-	-	-
Transition Obligation	11.4	22.7	11.3	0.2	0.5	0.2

The Company amortizes the prior service cost on an individual subsidiary basis and amortizes unrecognized net actuarial gains/(losses) and any remaining transition obligation over the remaining service lives of its employees as calculated on an NU consolidated basis. The pension transition obligation is fully amortized and the PBOP transition obligation will be fully amortized in 2013.

The components of net periodic benefit expense/(income), the portion of pension amounts capitalized related to employees working on capital projects, and intercompany allocations not included in the net periodic benefit expense amounts for the Pension and PBOP Plans are as follows:

	For the Year Ended December 31, 2011							
	Pension and SERP				**PBOP**			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 55.4	$ 19.5	$ 10.6	$ 3.9	$ 9.2	$ 2.9	$ 1.9	$ 0.6
Interest Cost	153.3	51.9	24.4	10.7	25.7	10.0	4.8	2.2
Expected Return on Plan Assets	(170.8)	(76.6)	(19.8)	(17.7)	(21.6)	(8.7)	(4.3)	(2.0)
Actuarial Loss	84.2	33.4	10.7	7.1	19.0	7.2	3.2	1.1
Prior Service Cost/(Credit)	9.7	4.2	1.8	0.9	(0.3)	-	-	1.3
Net Transition Obligation Cost	-	-	-	-	11.6	6.2	2.5	
Total Net Periodic Benefit Expense	$ 131.8	$ 32.4	$ 27.7	$ 4.9	$ 43.6	$ 17.6	$ 8.1	$ 3.2
Related Intercompany Allocations	N/A	$ 34.1	$ 7.6	$ 6.2	N/A	$ 8.2	$ 2.0	$ 1.5
Capitalized Pension Expense	$ 29.7	$ 16.6	$ 7.6	$ 2.7				

	For the Year Ended December 31, 2010							
	Pension and SERP				PBOP			
(Millions of Dollars)	NU	CL&P	PSNH	WMECO	NU	CL&P	PSNH	WMECO
Service Cost	$ 51.0	$ 17.6	$ 10.0	$ 3.5	$ 8.5	$ 2.7	$ 1.8	$ 0.6
Interest Cost	152.6	52.2	24.1	10.7	26.8	10.5	5.0	2.3
Expected Return on Plan Assets	(182.6)	(85.8)	(14.7)	(19.5)	(21.7)	(8.7)	(4.3)	(2.1)
Actuarial Loss	53.5	20.7	7.2	4.3	16.7	6.3	2.7	0.9
Prior Service Cost/(Credit)	9.9	4.2	1.8	0.9	(0.3)	-	-	-
Net Transition Obligation Cost	-	-	-	-	11.6	6.1	2.5	1.3
Total Net Periodic Benefit Expense/(Income)	$ 84.4	$ 8.9	$ 28.4	$ (0.1)	$ 41.6	$ 16.9	$ 7.7	$ 3.0
Related Intercompany Allocations	N/A	$ 25.2	$ 6.0	$ 4.5	N/A	$ 7.9	$ 2.0	$ 1.4
Capitalized Pension Expense	$ 16.9	$ 3.8	$ 6.9	$ -				

	For the Year Ended December 31, 2009							
	Pension and SERP				PBOP			
(Millions of Dollars)	NU	CL&P	PSNH	WMECO	NU	CL&P	PSNH	WMECO
Service Cost	$ 45.8	$ 16.0	$ 8.9	$ 3.3	$ 7.2	$ 2.2	$ 1.5	$ 0.5
Interest Cost	155.7	54.5	24.4	11.1	29.1	11.5	5.4	2.5
Expected Return on Plan Assets	(189.4)	(89.0)	(15.0)	(20.0)	(20.9)	(8.3)	(4.1)	(2.0)
Actuarial Loss	21.0	8.9	3.2	1.8	10.5	4.0	1.7	0.4
Prior Service Cost/(Credit)	9.9	4.2	1.8	0.9	(0.3)	-	-	-
Net Transition Obligation Cost	0.3	-	0.3	-	11.6	6.1	2.5	1.3
Total Net Periodic Benefit Expense/(Income)	$ 43.3	$ (5.4)	$ 23.6	$ (2.9)	$ 37.2	$ 15.5	$ 7.0	$ 2.7
Related Intercompany Allocations	N/A	$ 16.3	$ 3.6	$ 2.7	N/A	$ 7.3	$ 1.7	$ 1.1
Capitalized Pension Expense	$ 6.2	$ (2.6)	$ 6.0	$ (1.2)				

The following assumptions were used to calculate Pension and PBOP expense and income amounts:

	For the Years Ended December 31,					
	Pension and SERP			PBOP		
	2011	2010	2009	2011	2010	2009
Discount Rate	5.57%	5.98%	6.89%	5.28%	5.73%	6.90%
Expected Long-Term Rate of Return	8.25%	8.75%	8.75%	N/A	N/A	N/A
Compensation/Progression Rate	3.50%	4.00%	4.00%	N/A	N/A	N/A

Expected Long-Term Rate of Return -						
Health Assets, Taxable	N/A	N/A	N/A	6.45%	6.85%	6.85%
Life Assets and Non-Taxable Health Assets	N/A	N/A	N/A	8.25%	8.75%	8.75%

For 2011 through 2013, the health care cost trend assumption is 7 percent, subsequently decreasing 50 basis points per year to an ultimate rate of 5 percent in 2017.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point for the year ended December 31, 2011 would have the following effects:

(Millions of Dollars) **NU**	**One Percentage Point Increase**	**One Percentage Point Decrease**
Effect on Postretirement Benefit Obligation	$ 16.2	$ (13.5)
Effect on Total Service and Interest Cost Components	1.2	(1.0)

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

NU *(Millions of Dollars)*	**Pension and SERP Benefits**	**PBOP Benefits**	**Government Subsidy**
2012	$ 145.4	$ 41.4	$ (4.7)
2013	152.8	42.0	(5.0)
2014	159.5	42.4	(5.4)
2015	166.3	42.7	(5.7)
2016	173.7	42.9	(6.0)
2017-2021	983.9	215.7	(34.9)

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

Contributions: NU s policy is to annually fund the Pension Plan in an amount at least equal to an amount that will satisfy the requirements of ERISA, as amended by the PPA of 2006, and the Internal Revenue Code. A contribution of $143.6 million ($112.6 million of which was contributed by PSNH) was made in 2011. Based on the current status of the Pension Plan, NU is required to make a contribution to the Pension Plan of approximately $197.3 million in 2012, which will be made in quarterly installments, to meet minimum current funding requirements under the PPA.

For the PBOP plan, it is NU s policy to annually fund an amount equal to the PBOP Plan s postretirement benefit cost, excluding curtailment and termination benefits. NU contributed $43.8 million to the PBOP plan in 2011 and expects to make $44.7 million in contributions to the PBOP plan in 2012. NU also makes an additional contribution to the PBOP plan for the amounts received from the federal Medicare subsidy. This amount was $3.7 million in 2011 and is expected to be $4.7 million in 2012.

Fair Value of Pension and PBOP Assets: Pension and PBOP funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for Pension and PBOP payments. NU's investment strategy for its Pension and PBOP Plans is to maximize the long-term rates of return on these plans' assets within an acceptable level of risk. The investment strategy for each asset category includes a diversification of asset types, fund strategy and fund managers and establishes target asset allocations that are routinely reviewed and periodically rebalanced. In 2011, PBOP assets are comprised of specific assets within the defined benefit pension plan trust (401(h) assets) as well as assets held in the PBOP Plans. The investment policy and strategy of the 401(h) assets is consistent with those of the defined benefit pension plans, which are detailed below. NU's expected long-term rates of return on Pension and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension and PBOP Plans, NU evaluated input from actuaries and consultants, as well as long-term inflation assumptions and historical returns. As of December 31, 2011, management has assumed long-term rates of return of 8.25 percent on Pension and PBOP Plan assets. These long-term rates of return are based on the assumed rates of return for the target asset allocations as follows:

	As of December 31,					
	Pension and PBOP 2011		Pension and PBOP Life and Non-Taxable Health 2010		PBOP Taxable Health 2010	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:						
United States	24%	9%	24%	9%	55%	9%
International	13%	9%	13%	9%	15%	9%
Emerging Markets	3%	10%	3%	10%	-	-
Private Equity	12%	13%	12%	13%	-	-
Debt Securities:						
Fixed Income	20%	5%	20%	5%	30%	5%
High Yield Fixed Income	3.5%	7.5%	3.5%	7.5%	-	-

Emerging Markets Debt	3.5%	7.5%	3.5%	7.5%	-	-
Real Estate and Other Assets	8%	7.5%	8%	7.5%	-	-
Hedge Funds	13%	7%	13%	7%	-	-

The following table presents, by asset category, the Pension and PBOP Plan assets recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	Pension Plan Fair Value Measurements as of December 31,							
(Millions of Dollars)	2011				2010			
Asset Category:	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Equity Securities:								
United States [1]	$ 218.7	$ 14.8	$ 259.4	$ 492.9	$ 256.3	$ 46.9	$ 266.0	$ 569.2
International [1]	20.0	221.9	-	241.9	6.4	250.9	-	257.3
Emerging Markets [1]	-	66.6	-	66.6	-	81.1	-	81.1
Private Equity	11.3	-	255.1	266.4	6.9	-	229.5	236.4
Fixed Income [2]	17.8	268.7	276.2	562.7	7.6	261.6	247.6	516.8
Real Estate and Other Assets	24.8	57.8	71.8	- 154.4	-	26.0	43.7	69.7
Hedge Funds	-	-	240.0	240.0	-	-	247.1	247.1
Total Master Trust Assets	$ 292.6	$ 629.8	$ 1,102.5	$ 2,024.9	$ 277.2	$ 666.5	$ 1,033.9	$ 1,977.6
Less: 401(h) PBOP Assets				(19.0)				-
Total Pension Assets				$ 2,005.9				$ 1,977.6

	PBOP Plan Fair Value Measurements as of December 31,							
(Millions of Dollars)	2011				2010			
Asset Category:	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and Cash Equivalents	$ 5.9	$ -	$ -	$ 5.9	$ 4.4	$ -	$ -	$ 4.4
Equity Securities:								
United States	116.9	-	10.7	127.6	132.1	-	10.1	142.2
International	29.6	-	-	29.6	34.8	-	-	34.8
Emerging Markets	4.6	-	-	4.6	7.7	-	-	7.7
Debt Securities:								
Fixed Income [2]	-	34.9	26.0	60.9	-	35.3	23.4	58.7
High Yield Fixed Income	-	4.5	-	4.5	-	4.4	-	4.4
Emerging Market Debt	-	4.9	-	4.9	-	4.8	-	4.8
Hedge Funds	-		16.1	16.1	-	-	16.4	16.4
Private Equity	-	-	5.1	5.1	-	-	0.3	0.3
Real Estate and Other Assets	-	4.7	2.5	7.2	-	4.8	-	4.8
Total	$ 157.0	$ 49.0	$ 60.4	$ 266.4	$ 179.0	$ 49.3	$ 50.2	$ 278.5
Add: 401(h) PBOP Assets				19.0				-

Total PBOP Assets	$ 285.4	$ 278.5

(1)

United States, International and Emerging Markets equity securities classified as Level 2 include investments in commingled funds and unrealized gains/(losses) on holdings in equity index swaps. Level 3 investments include hedge funds that are overlayed with equity index swaps and futures contracts.

(2)

Fixed Income investments classified as Level 3 investments include fixed income funds that invest in a variety of opportunistic fixed income strategies, and hedge funds that are overlayed with fixed income futures.

The Company values assets based on observable inputs when available. Equity securities, exchange traded funds and futures contracts classified as Level 1 in the fair value hierarchy are priced based on the closing price on the primary exchange as of the balance sheet date. Commingled funds included in Level 2 equity securities are recorded at the net asset value provided by the asset manager, which is based on the market prices of the underlying equity securities. Swaps are valued using pricing models that incorporate interest rates and equity and fixed income index closing prices to determine a net present value of the cash flows. Fixed income securities, such as government issued securities, corporate bonds and high yield bond funds, are included in Level 2 and are valued 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. Hedge funds and investments in opportunistic fixed income funds are recorded at net asset value based on the values of the underlying assets. The assets in the hedge funds and opportunistic fixed income funds are valued using observable inputs and are classified as Level 3 within the fair value hierarchy due to redemption restrictions. Private Equity investments and Real Estate and Other Assets are valued using the net asset value provided by the partnerships, which are based on discounted cash flows of the underlying investments, real estate appraisals or public market comparables of the underlying investments. These investments are classified as Level 3 due to redemption restrictions.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3): The following tables present changes for the Level 3 category of Pension and PBOP Plan assets for the years ended December 31, 2011 and 2010:

	Pension Plan					
(Millions of Dollars)	**United States Equity**	**Private Equity**	**Fixed Income**	**Real Estate and Other Assets**	**Hedge Funds**	**Total**
Balance as of January 1, 2010	$ 252.1	$ 193.8	$ 174.0	$ 38.5	$ 231.2	$ 889.6
Actual Return on Plan Assets:						
Relating to Assets Still Held as of Year End	13.9	10.9	21.0	0.5	15.9	62.2
Relating to Assets Distributed During the Year	-	-	-	0.5	-	0.5
Purchases, Sales and Settlements	-	24.8	52.6	4.2	-	81.6
Balance as of December 31, 2010	$ 266.0	$ 229.5	$ 247.6	$ 43.7	$ 247.1	$ 1,033.9
Actual Return on Plan Assets:						
Relating to Assets Still Held as of Year End	(6.6)	20.0	(1.5)	1.6	(7.1)	6.4
Relating to Assets Distributed During the Year	-	19.5	(2.8)	0.3	-	17.0
Purchases, Sales and Settlements	-	(13.9)	32.9	26.2	-	45.2
Balance as of December 31, 2011	$ 259.4	$ 255.1	$ 276.2	$ 71.8	$ 240.0	$ 1,102.5

	PBOP Plan					
(Millions of Dollars)	**United States Equity**	**Private Equity**	**Fixed Income**	**Real Estate and Other Assets**	**Hedge Funds**	**Total**
Balance as of January 1, 2010	$ -	$ -	$ 24.6	$ -	$ -	$ 24.6
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held as of Year End	0.5	-	3.2	-	0.4	4.1
Purchases, Sales and Settlements	9.6	0.3	(4.4)	-	16.0	21.5
Balance as of December 31, 2010	$ 10.1	$ 0.3	$ 23.4	$ -	$ 16.4	$ 50.2
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held as of Year End	0.6	0.6	0.2	(0.1)	(0.3)	1.0
Purchases, Sales and Settlements	-	4.2	2.4	2.6		9.2
Balance as of December 31, 2011	$ 10.7	$ 5.1	$ 26.0	$ 2.5	$ 16.1	$ 60.4

B.

Defined Contribution Plans

NU maintains a 401(k) Savings Plan for substantially all employees, including CL&P, PSNH and WMECO employees. This savings plan provides for employee contributions up to specified limits. NU matches employee contributions up to a maximum of three percent of eligible compensation with one percent in cash and two percent in NU common shares allocated from the ESOP. The 401(k) matching contributions of cash and NU common shares were as follows:

(Millions of Dollars)	NU	CL&P	PSNH	WMECO
2011	$ 13.2	$ 4.0	$ 2.5	$ 0.8
2010	12.7	4.0	2.4	0.8
2009	12.2	3.9	2.3	0.7

Effective on January 1, 2006, all newly hired, non-bargaining unit employees, and effective on January 1, 2007 or as subject to collective bargaining agreements, certain newly hired bargaining unit employees participate in a program under the 401(k) Savings Plan called the K-Vantage benefit. These employees are not eligible to participate in the Pension Plan. In addition, participants in the Pension Plan as of January 1, 2006 were given the opportunity to choose to become a participant in the K-Vantage benefit beginning in 2007, in which case their benefit under the Pension Plan was frozen. NU makes contributions to the K-Vantage benefit based on a percentage of participants' eligible compensation, as defined by the benefit document. The contributions made were as follows:

(Millions of Dollars)	NU	CL&P	PSNH	WMECO
2011	$ 4.2	$ 0.5	$ 0.6	$ 0.1
2010	3.4	0.4	0.4	0.1
2009	2.6	0.2	0.3	-

C.

Employee Stock Ownership Plan

NU maintains an ESOP for purposes of allocating shares to NU, CL&P, PSNH and WMECO's employees participating in NU's 401(k) Savings Plan. NU issued unsecured notes during 1991 and 1992 totaling $250 million, the proceeds of which were loaned to the ESOP trust (ESOP Notes) for the purchase of 10.8 million newly issued NU common shares (ESOP shares). During 2010, the ESOP Notes were fully repaid and all ESOP shares purchased with the proceeds of the ESOP Notes were fully allocated. As of December 31, 2011 and 2010, total allocated ESOP shares were 10,800,185. Following complete allocation of the ESOP shares, continuing allocations of NU common shares were made from NU treasury shares to satisfy the 401(k) Savings Plan obligation to provide a portion of the matching contribution in NU common shares. NU's contributions to the ESOP trust for the years ended December 31, 2010 and 2009 totaled $1.1 million and $6.1 million, respectively. As the ESOP notes were fully repaid in 2010, no contributions were made in 2011. In 2010, the ESOP trust allocated 127,054 of NU common shares to satisfy 401(k) Savings Plan obligations to employees.

For treasury shares used to satisfy the 401(k) Savings Plan matching contributions, compensation expense is recognized equal to the fair value of shares that have been allocated to participants. Any difference between the fair value and the average cost of the allocated treasury shares is charged or credited to Capital Surplus, Paid In. For the years ended December 31, 2011, 2010 and 2009, NU recognized \$8.8 million, \$8.5 million and \$8.2 million, respectively, of expense related to the ESOP.

Dividends on the ESOP unallocated shares are not considered dividends for financial reporting purposes. For the years ended 2011, 2010 and 2009, NU paid quarterly dividends of $0.275 per share, $0.25625 per share and $0.2375 per share, respectively.

D.

Share-Based Payments

In accordance with accounting guidance for share-based payments, share-based compensation awards are recorded using the fair value-based method based on the fair value at the date of grant. This guidance applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed. NU, CL&P, PSNH and WMECO record compensation cost related to these awards, as applicable, for shares issued or sold to NU, CL&P, PSNH and WMECO employees and officers, as well as the allocation of costs associated with shares issued or sold to NUSCO employees and officers that support CL&P, PSNH and WMECO.

NU Incentive Plan: NU maintains long-term equity-based incentive plans under the NU Incentive Plan in which NU, CL&P, PSNH and WMECO employees, officers and board members are entitled to participate. The NU Incentive Plan was approved in 2007, and authorized NU to grant up to 4,500,000 new shares for various types of awards, including RSUs and performance shares, to eligible employees, officers, and board members. As of December 31, 2011 and 2010, NU had 2,685,615 and 3,068,850 common shares, respectively, available for issuance under the NU Incentive Plan. In addition to the NU Incentive Plan, NU maintains an ESPP for all eligible NU, CL&P, PSNH and WMECO employees.

NU accounts for its various share-based plans as follows:

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For grants of RSUs, NU records compensation expense, net of estimated forfeitures, on a straight-line basis over the vesting period based upon the fair value of NU's common shares at the date of grant. Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.

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For grants of performance shares, NU records compensation expense, net of estimated forfeitures, on a straight-line basis over the vesting period. Performance shares vest based upon the extent to which Company goals are achieved. For the majority of performance shares, fair value is based upon the value of NU's common shares at the date of grant and compensation expense is recorded based upon the probable outcome of the achievement of Company targets. The fair value of the remaining performance shares are based upon the achievement of the Company's share price as compared to an index of similar equity securities. The fair value at the date of grant for these remaining performance shares was determined using a lattice model and compensation expense is recorded over the vesting period.

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For shares sold under the ESPP, no compensation expense is recorded, as the ESPP qualifies as a non-compensatory plan.

For the years ended December 31, 2011, 2010 and 2009, additional tax benefits totaling $1.3 million, $0.9 million and $0.9 million, respectively, increased cash flows from financing activities.

RSUs: NU has granted RSUs under the 2004 through 2011 incentive programs that are subject to three-year and four-year graded vesting schedules for employees, and one-year graded vesting schedules for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of RSU transactions is as follows:

RSUs	**RSUs (Units)**		**Weighted Average Grant-Date Fair Value**
Outstanding as of January 1, 2009	912,991	$	24.75
Granted	347,112	$	23.26
Shares issued	(203,888)	$	25.55
Forfeited	(18,303)	$	26.26
Outstanding as of December 31, 2009	1,037,912	$	24.07
Granted	258,174	$	26.03
Shares issued	(267,951)	$	25.05
Forfeited	(13,656)	$	24.26
Outstanding as of December 31, 2010	1,014,479	$	24.31
Granted	208,533	$	33.87
Shares issued	(244,782)	$	24.47
Forfeited	(18,310)	$	23.74
Outstanding as of December 31, 2011	959,920	$	26.36

As of December 31, 2011 and 2010, the number and weighted average grant-date fair value of unvested RSUs was 403,108 and $28.70 per share, and 519,900 and $24.77 per share, respectively. The number and weighted average grant-date fair value of RSUs vested during 2011 was 292,185 and $25.25 per share, respectively. As of December 31, 2011, 556,812 RSUs were fully vested and an additional 382,953 are expected to vest.

On November 16, 2010, NU granted 192,309 RSUs to certain executives, contingent upon completion of the pending merger with NSTAR, with a three year vesting period that would begin as of the closing date of the merger.

Performance Shares: NU has granted performance shares under the 2009, 2010 and 2011 incentive programs that vest based upon the extent to which the Company achieves targets at the end of each respective three-year performance measurement period.

Performance shares are paid in shares, after the performance measurement period. A summary of performance share transactions is as follows:

Performance Shares	**Performance Shares (Units)**		**Weighted Average Grant-Date Fair Value**
Outstanding as of January 1, 2009	-	$	-
Granted	104,150	$	23.93
Shares issued	-	$	-
Forfeited	(5,064)	$	23.96
Outstanding as of December 31, 2009	99,086	$	23.93
Granted	149,520	$	25.24
Shares issued	-	$	-
Forfeited	(47)	$	23.96
Outstanding as of December 31, 2010	248,559	$	24.72
Granted	244,870	$	33.76
Shares issued	-	$	-
Forfeited	(10,296)	$	30.47
Outstanding as of December 31, 2011	483,133	$	29.18

As of December 31, 2011, performance shares vested at 100 percent of target under the 2009 incentive program. Such shares will be distributed to participants in the form of NU common shares prior to March 15, 2012. Under this performance plan, 105,934 shares vested, with a weighted-average grant date fair value of $24.42 per share.

As of December 31, 2011 and 2010, there were 377,199 and 248,559 unvested performance shares with a weighted-average grant date fair value of $30.52 per share and $24.72 per share, respectively. As of December 31, 2011, based upon the probable outcome of certain performance metrics, performance shares are expected to vest at 115 percent of target under the 2010 incentive program, and at 98 percent of target under the 2011 incentive program.

The total compensation cost recognized by NU, CL&P, PSNH and WMECO for share-based compensation awards was as follows:

NU	**For the Years Ended December 31,**					
(Millions of Dollars)	**2011**		**2010**		**2009**	
Compensation Cost Recognized	$	12.3	$	10.5	$	8.8
Associated Future Income Tax Benefit Recognized		4.9		4.2		3.5

	For the Years Ended December 31,																	
	2011						**2010**						**2009**					
(Millions of Dollars)	**CL&P**		**PSNH**		**WMECO**		**CL&P**		**PSNH**		**WMECO**		**CL&P**		**PSNH**		**WMECO**	
Compensation Cost Recognized	$	7.1	$	2.5	$	1.4	$	6.2	$	2.1	$	1.1	$	5.3	$	1.7	$	0.9

Associated Future Income Tax Benefit Recognized	2.8	1.0	0.6	2.5	0.9	0.4	2.1	0.7	0.4

As of December 31, 2011, there was $8.9 million of total unrecognized compensation cost related to nonvested share-based awards for NU, $5.0 million for CL&P, $1.8 million for PSNH and $1.0 million for WMECO. This cost is expected to be recognized ratably over a weighted-average period of 1.77 years for NU, CL&P and PSNH and 1.76 years for WMECO.

Stock Options: Prior to 2003, NU granted stock options to certain employees. The options expire ten years from the date of grant. All options were fully vested as of December 31, 2005. The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average remaining contractual lives for the options outstanding as of December 31, 2011 is 0.3 years. No compensation expense related to stock options was recorded for the years ended December 31, 2011, 2010 or 2009. A summary of stock option transactions is as follows:

		Exercise Price Per Share		
	Options	**Range**	**Weighted Average**	**Intrinsic Value (Millions)**
Outstanding and exercisable - January 1, 2009	320,920	$ 14.94 - $ 21.03	$ 18.83	
Exercised	(95,704)		$ 18.54	$ 0.6
Forfeited and cancelled	-		$ -	
Outstanding and exercisable - December 31, 2009	225,216	$ 17.40 - $ 21.03	$ 18.96	
Exercised	(112,617)		$ 19.12	$ 1.0
Forfeited and cancelled	-		$ -	
Outstanding and exercisable - December 31, 2010	112,599	$ 17.40 - $ 21.03	$ 18.80	
Exercised	(65,225)		$ 18.81	$ 1.0
Forfeited and cancelled	-		$ -	
Outstanding and exercisable - December 31, 2011	47,374	$ 18.58 - $ 18.90	$ 18.78	$ 0.8

Cash received for options exercised during the year ended December 31, 2011 totaled $1.2 million. The tax benefit realized from stock options exercised totaled $0.4 million for the year ended December 31, 2011.

Employee Share Purchase Plan: NU maintains an ESPP for all eligible NU, CL&P, PSNH, and WMECO employees, which allows for NU common shares to be purchased by employees at the end of successive six-month offering periods at 95 percent of the closing market price on the last day of each six-month period. Employees are permitted to purchase shares having a value not exceeding 25 percent of their compensation as of the beginning of the offering period up to a limit of $25,000 per annum. The ESPP qualifies as a non-compensatory plan under accounting guidance for share-based payments, and no compensation expense is recorded for ESPP purchases.

During 2011, employees purchased 35,476 shares at discounted prices of $31.27 and $32.30. Employees purchased 38,672 shares in 2010 at discounted prices of $26.45 and $24.05. As of December 31, 2011 and 2010, 896,702 and 932,178 shares, respectively, remained available for future issuance under the ESPP.

An income tax rate of 40 percent is used to estimate the tax effect on total share-based payments determined under the fair value-based method for all awards. The Company generally settles stock option exercises and fully vested RSUs and performance shares with the issuance of new common shares.

E.

Other Retirement Benefits

NU provides benefits for retirement and other benefits for certain current and past company officers of NU, including CL&P, PSNH and WMECO. These benefits are accounted for on an accrual basis and expensed over the service lives of the employees. The actuarially-determined liability for these benefits, which is included in Other Long-Term Liabilities on the accompanying consolidated balance sheets, as well as the related expense, were as follows:

NU	**For the Years Ended December 31,**		
(Millions of Dollars)	**2011**	**2010**	**2009**
Actuarially-Determined Liability	$ 52.8	$ 49.9	$ 47.9
Other Retirement Benefits Expense	4.7	4.2	3.9

	For the Years Ended December 31,								
	2011			**2010**			**2009**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Actuarially-Determined Liability	$ 1.2	$ 2.5	$ 0.2	$ 0.4	$ 2.4	$ 0.2	$ 0.4	$ 2.4	$ 0.2
Other Retirement Benefits Expense	2.6	1.0	0.5	2.3	0.9	0.4	2.2	0.9	0.4

11.

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 authoritative literature. Details of income tax expense and the components of the federal and state income tax provisions are as follows:

NU	**For the Years Ended December 31,**		
(Millions of Dollars)	**2011**	**2010**	**2009**
Current Income Taxes:			
Federal	$ 3.0	$ 9.0	$ 4.5
State	(26.0)	(6.5)	52.7
Total Current	(23.0)	2.5	57.2
Deferred Income Taxes, Net:			
Federal	187.7	201.2	155.1
State	9.1	9.7	(29.2)
Total Deferred	196.8	210.9	125.9
Investment Tax Credits, Net	(2.8)	(3.0)	(3.2)
Income Tax Expense	$ 171.0	$ 210.4	$ 179.9

	For the Years Ended December 31,								
	2011			**2010**			**2009**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Current Income Taxes:									
Federal	$ 13.9	$ (25.8)	$ 0.1	$ 20.7	$ 6.1	$ 3.1	$ 28.3	$ (8.9)	$ (8.6)
State	(34.4)	0.1	0.3	(1.1)	5.6	2.5	40.1	5.8	0.9
Total Current	(20.5)	(25.7)	0.4	19.6	11.7	5.6	68.4	(3.1)	(7.7)
Deferred Income Taxes, Net:									
Federal	106.4	67.7	22.1	108.1	37.6	11.0	80.5	34.4	21.3
State	6.2	7.9	1.0	7.0	1.6	-	(27.6)	0.8	1.6
Total Deferred	112.6	75.6	23.1	115.1	39.2	11.0	52.9	35.2	22.9
Investment Tax Credits, Net	(2.1)	-	(0.3)	(2.3)	(0.1)	(0.3)	(2.5)	(0.1)	(0.3)
Income Tax Expense	$ 90.0	$ 49.9	$ 23.2	$ 132.4	$ 50.8	$ 16.3	$ 118.8	$ 32.0	$ 14.9

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

NU	**For the Years Ended December 31,**		
(Millions of Dollars, except percentages)	**2011**	**2010**	**2009**
Income Before Income Tax Expense	$ 571.5	$ 604.5	$ 515.5
Statutory Federal Income Tax Expense at 35%	200.0	211.6	180.4
Tax Effect of Differences:			
Depreciation	(14.2)	(9.5)	(2.7)
Investment Tax Credit Amortization	(2.8)	(3.0)	(3.2)
Other Federal Tax Credits	(3.5)	(3.8)	(3.8)
State Income Taxes, Net of Federal Impact	22.1	12.5	11.5
Medicare Subsidy	-	15.6	(3.5)
Tax Asset Valuation Allowance/Reserve Adjustments	(33.1)	(10.5)	3.8
Other, Net	2.5	(2.5)	(2.6)
Income Tax Expense	$ 171.0	$ 210.4	$ 179.9
Effective Tax Rate	29.9 %	34.8 %	34.9 %

	For the Years Ended December 31,								
	2011			**2010**			**2009**		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Income Before Income Tax Expense	$ 340.2	$ 150.2	$ 66.2	$ 376.6	$ 140.9	$ 39.4	$ 335.2	$ 97.6	$ 41.1
Statutory Federal Income Tax Expense at 35%	119.1	52.6	23.2	131.8	49.3	13.8	117.3	34.1	14.4
Tax Effect of Differences:									
Depreciation	(8.1)	(4.4)	0.1	(6.1)	(3.2)	0.2	(1.7)	(1.2)	0.3
Investment Tax Credit Amortization	(2.1)	-	(0.3)	(2.3)	(0.1)	(0.3)	(2.5)	(0.1)	(0.3)
Other Federal Tax Credits	(0.1)	(3.4)	-	(0.1)	(3.6)	-	(0.1)	(3.7)	-

State Income Taxes, Net of Federal Impact	4.0	5.2	0.9	8.5	4.7	1.6	8.9	4.3	1.6
Medicare Subsidy	-	-	-	7.8	3.8	1.5	(1.3)	(0.6)	(0.3)
Tax Asset Valuation Allowance/ Reserve Adjustments	(22.3)	-	-	(4.7)	-	-	(0.8)	-	-
Other, Net	(0.5)	(0.1)	(0.7)	(2.5)	(0.1)	(0.5)	(1.0)	(0.8)	(0.8)
Income Tax Expense	$ 90.0	$ 49.9	$ 23.2	$ 132.4	$ 50.8	$ 16.3	$ 118.8	$ 32.0	$ 14.9
Effective Tax Rate	26.5 %	33.2 %	35.0 %	35.2 %	36.1 %	41.4 %	35.4 %	32.8 %	36.3 %

NU, CL&P, PSNH and WMECO file a consolidated federal income tax return and unitary, combined and separate state income tax returns. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

The tax effects of temporary differences that give rise to the net accumulated deferred tax obligations are as follows:

NU	As of December 31,	
(Millions of Dollars)	**2011**	**2010**
Deferred Tax Assets:		
Employee Benefits	$ 539.6	$ 470.1
Derivative Liabilities and Change in Fair Value of Energy Contracts	415.3	376.5
Regulatory Deferrals	157.9	135.5
Allowance for Uncollectible Accounts	45.4	46.4
Tax Effect - Tax Regulatory Assets	15.5	17.0
Federal Net Operating Loss Carryforwards	178.6	-
Other	204.2	188.0
Total Deferred Tax Assets	1,556.5	1,233.5
Less: Valuation Allowance	4.6	19.8
Net Deferred Tax Assets	$ 1,551.9	$ 1,213.7
Deferred Tax Liabilities:		
Accelerated Depreciation and Other Plant-Related Differences	$ 1,920.5	$ 1,612.6
Property Tax Accruals	58.9	55.1
Regulatory Amounts:		
Other Regulatory Deferrals	1,135.0	873.3
Tax Effect - Tax Regulatory Assets	184.6	177.1

	Securitized Contract Termination Costs		39.6		65.8
	Derivative Assets		39.1		48.0
	Other		24.5		26.3
Total Deferred Tax Liabilities		$	3,402.2	$	2,858.2

	As of December 31,					
	2011			2010		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Deferred Tax Assets:						
Derivative Liabilities and Change in Fair Value of Energy Contracts	$ 412.2	$ -	$ 2.9	$ 371.2	$ 5.1	$ -
Allowance for Uncollectible Accounts	32.4	3.0	3.9	31.5	2.9	5.6
Regulatory Deferrals	78.4	39.3	15.0	68.9	34.4	6.5
Employee Benefits	121.4	87.9	13.3	66.9	125.0	2.4
Tax Effect - Tax Regulatory Assets	6.4	1.6	6.5	7.4	1.6	6.9
Federal Net Operating Loss Carryforwards	85.5	60.8	-	-	-	-
Other	76.0	26.0	17.6	82.5	13.6	10.1
Total Deferred Tax Assets	$ 812.3	$ 218.6	$ 59.2	$ 628.4	$ 182.6	$ 31.5
Deferred Tax Liabilities:						
Accelerated Depreciation and Other Plant-Related Differences	$ 1,046.9	$ 423.8	$ 194.9	$ 917.0	$ 309.8	$ 168.4
Property Tax Accruals	41.9	4.5	3.4	39.5	4.2	3.2
Regulatory Amounts:						
Securitized Contract Termination Costs	-	29.7	10.0	(0.8)	50.4	16.2
Other Regulatory Deferrals	734.2	122.5	79.3	546.6	105.1	51.1
Tax Effect - Tax Regulatory Assets	141.8	16.1	13.7	138.5	14.0	13.7
Derivative Assets	39.1	-	-	47.9	-	-
Other	8.2	14.0	1.1	8.4	15.7	2.9
Total Deferred Tax Liabilities	$ 2,012.1	$ 610.6	$ 302.4	$ 1,697.1	$ 499.2	$ 255.5

As of December 31, 2011, NU, CL&P, PSNH and WMECO have adjusted the presentation of Deferred Tax Assets and Liabilities. Amounts as of December 31, 2010 have been reclassified to conform to the December 31, 2011 presentation.

As of December 31, 2011, NU had state credit carryforwards of $101.4 million that begin expiring in 2013. NU s state net operating loss carryforward as of December 31, 2011 was not significant. As of December 31, 2010, NU had state net operating loss carryforwards of $317.7 million that expire between December 31, 2011 and December 31, 2027 and state credit carryforwards of $84.9 million that begin expiring in 2013. The state net operating loss carryforward deferred tax asset has been fully reserved by a valuation allowance. As of December 31, 2011, NU had a federal net operating loss carryforward of $510.2 million and federal credit carryforwards of $6.6 million that expire December 31, 2031.

As of December 31, 2011, CL&P had state tax credit carryforwards of $68.6 million that begin expiring in 2013. As of December 31, 2010, CL&P had state tax credit carryforwards of $56.1 million that begin expiring in 2013. As of December 31, 2011, CL&P had a federal net operating loss carryforward of $244.2 million that expires December 31, 2031.

As of December 31, 2011, PSNH had a $173.8 million federal net operating loss carryforward and a $3.4 million federal credit carryforward that expire December 31, 2031.

As of December 31, 2011, WMECO had a $3.2 million federal credit carryforward that expires December 31, 2031.

Unrecognized Tax Benefits: A reconciliation of the activity in unrecognized tax benefits from January 1, 2009 to December 31, 2011, all of which would impact the effective tax rate, if recognized, is as follows:

(Millions of Dollars)		**NU**		**CL&P**		**PSNH**		**WMECO**
Balance as of January 1, 2009	$	156.3	$	106.4	$	12.4	$	3.8
Gross Increases - Current Year		12.3		8.6		-		-
Settlement		(44.2)		(26.0)		(12.4)		(3.8)
Lapse of Statute of Limitations		(0.1)		-		-		-
Balance as of December 31, 2009		124.3		89.0		-		-
Gross Increases - Current Year		10.8		5.3		-		-
Gross Increases - Prior Year		0.8		-		-		-
Settlement		(34.3)		(13.5)		-		-
Lapse of Statute of Limitations		(0.4)		-		-		-
Balance as of December 31, 2010		101.2		80.8		-		-
Gross Increases - Current Year		8.0		1.4		-		-
Gross Decreases - Prior Year		(35.7)		(35.7)		-		-
Balance as of December 31, 2011	$	73.5	$	46.5	$	-	$	-

Interest and Penalties: Interest on uncertain tax positions is recorded and generally classified as a component of Other Interest Expense. However, when resolution of uncertainties results in the Company receiving interest income, any related interest benefit is recorded in Other Income, Net on the accompanying consolidated statements of income. No penalties have been recorded. If penalties are recorded in the future, then the estimated penalties would be classified as a component of Other Income, Net on the accompanying consolidated statements of income. The components of interest on uncertain tax positions by company in 2011, 2010 and 2009 are as follows:

Other Interest	**For the Years Ended December 31,**						**Accrued Interest**	**As of December 31,**			
Expense/(Income)		**2011**		**2010**		**2009**	**Expense**		**2011**		**2010**
(Millions of Dollars)							*(Millions of Dollars)*				
CL&P	$	(3.7)	$	(7.4)	$	(4.2)	CL&P	$	2.7	$	6.4
PSNH		(0.6)		0.1		(1.3)	PSNH		-		0.6
WMECO		-		-		(0.4)	WMECO		-		-
NU Parent and Other		1.5		(17.5)		1.9	NU Parent and Other		4.4		2.9
Total	$	(2.8)	$	(24.8)	$	(4.0)	Total	$	7.1	$	9.9

Tax Positions: During 2011, NU recorded an after-tax benefit of $29.1 million related to various state tax settlements and certain other adjustments. This benefit is recorded as a reduction to both interest expense and income tax expense (including NU and CL&P tax expense reductions of approximately $22.4 million). NU is currently working to resolve the treatments of certain timing and other costs in the remaining open periods.

Tax Years: The following table summarizes NU, CL&P, PSNH and WMECO's tax years that remain subject to examination by major tax jurisdictions as of December 31, 2011:

Description	**Tax Years**
Federal	2011
Connecticut	2005-2011
New Hampshire	2008-2011
Massachusetts	2008-2011

While tax audits are currently ongoing, it is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. Management estimates that potential resolutions of differences of a non-timing nature, could result in a zero to $50 million decrease in unrecognized tax benefits by NU and a zero to $39 million decrease in unrecognized tax benefits by CL&P. These estimated changes could have an impact on NU's and CL&P's 2012 earnings of zero to $32 million and zero to $26 million, respectively. Other companies impacts are not expected to be material.

2010 Federal Legislation: On March 23, 2010, President Obama signed into law the 2010 Healthcare Act. The 2010 Healthcare Act was amended by a Reconciliation Bill signed into law on March 30, 2010. The 2010 Healthcare Act includes a provision that eliminated the tax deductibility of certain PBOP contributions for retiree prescription drug benefits. The tax deduction eliminated by this legislation represented a loss of previously recognized deferred income tax assets established through 2009 and as a result, these assets were written down by approximately $18 million in 2010. Since the electric and natural gas distribution companies are cost-of-service and rate-regulated, and approximately $15 million of the $18 million is able to be deferred and recovered through future rates, NU reduced 2010 earnings by $3 million of non-recoverable costs. In addition, as a result of the elimination of the tax deduction in 2010, NU was not able to recognize approximately $2 million of net annual benefits.

On September 27, 2010, President Obama signed into law the Small Business Jobs and Credit Act of 2010, which extends the bonus depreciation provisions of the American Recovery and Reinvestment Act of 2009 to small and large businesses through 2010. This extended stimulus provided NU with cash flow benefits of approximately $100 million.

On December 17, 2010, President Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act (2010 Tax Act), which, among other things, provides 100 percent bonus depreciation for tangible personal property placed in service after September 8, 2010, and through December 31, 2011. For tangible personal property placed in service after December 31, 2011, and through December 31, 2012, the 2010 Tax Act provides for 50 percent bonus depreciation.

12.

COMMITMENTS AND CONTINGENCIES

A.

Environmental Matters

General: NU, CL&P, PSNH and WMECO are subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. NU, CL&P, PSNH and WMECO have an active environmental auditing and training program and believe that they are substantially in compliance with all enacted laws and regulations.

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

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

The amounts recorded as environmental liabilities included in Other Current Liabilities and Other Long-Term Liabilities on the accompanying consolidated balance sheets represent management's best estimate of the liability for environmental costs, and take into consideration site assessment and remediation costs. NU, CL&P, PSNH and WMECO's environmental liability also takes into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate previously contaminated sites and any other infrequent and non-recurring clean up costs. A reconciliation of the activity in the environmental reserves is as follows:

(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**
Balance as of December 31, 2009	$ 26.0	$ 2.7	$ 5.3	$ 0.4
Additions	18.2	0.5	8.9	0.1
Payments	(7.1)	(0.4)	(5.1)	(0.2)
Balance as of December 31, 2010	37.1	2.8	9.1	0.3
Additions	1.6	0.4	0.1	0.1
Payments	(7.0)	(0.3)	(2.6)	(0.1)
Balance as of December 31, 2011	$ 31.7	$ 2.9	$ 6.6	$ 0.3

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. NU, CL&P, PSNH and WMECO have not recorded any probable recoveries from third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

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

As of December 31, 2011 and 2010, the number of environmental sites and reserves related to these sites for which remediation or long-term monitoring, preliminary site work or site assessment are being performed, as well as the portion related to MGP sites are as follows:

	As of December 31, 2011	**As of December 31, 2010**

	Number of Sites	Reserve (in millions)	Portion Related to MGP Sites (in millions)	Number of Sites	Reserve (in millions)	Portion Related to MGP Sites (in millions)
NU	59	$ 31.7	$ 28.9	58	$ 37.1	$ 35.2
CL&P	18	2.9	1.5	17	2.8	1.5
PSNH	18	6.6	5.8	18	9.1	8.3
WMECO	10	0.3	0.1	9	0.3	0.1

MGP sites are sites that were operated several decades ago and produced manufacturing gas from coal, which resulted in certain byproducts in the environment that may pose a risk to human health and the environment.

As of December 31, 2011, for 5 environmental sites (2 for PSNH and 1 for WMECO) that are included in the Company's reserve for environmental costs, the information known and nature of the remediation options at those sites allow for the Company to estimate the range of losses for environmental costs. As of December 31, 2011, $4.9 million ($0.7 million for PSNH) had been accrued as a liability for these sites, which represent management's best estimates of the liabilities for environmental costs. These amounts are the best estimates within estimated ranges of losses from $1.3 million to $16.8 million (zero to $4.1 million for PSNH and zero to $8.6 million for WMECO). For the sites that comprise the remaining $26.8 million of the environmental reserve ($2.9 million for CL&P, $5.9 million for PSNH and $0.3 million for WMECO), determining an estimated range of loss is not possible at this time.

As of December 31, 2011, in addition to the sites identified above, there were 12 sites (7 for CL&P, 2 for PSNH and 2 for WMECO) for which there are unasserted claims; however, any related site assessment or remediation costs are not probable or estimable at this time.

HWP: HWP, a subsidiary of NU, continues to investigate the potential need for additional remediation at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal utility, in 1902. HWP shares responsibility for site remediation with HG&E and has conducted substantial investigative and remediation activities. The cumulative expense recorded to the reserve for this site since 1994 through December 31, 2011 was $19.5 million, of which $17.1 million had been spent, leaving $2.4 million in the reserve as of December 31, 2011. For the year ended December 31, 2011, there was no charge recorded to the reserve and for the years ended December 31, 2010 and 2009, pre-tax charges of $2.6 million and $1.1 million, respectively, were recorded to reflect estimated costs associated with the site. HWP's share of the costs related to this site is not recoverable from customers.

In 2008, the MA DEP issued a letter to HWP and HG&E, representing guidance rather than a mandate, providing conditional authorization for additional investigatory and risk characterization activities and indicating that further removal of tar in certain areas was needed. HWP implemented several supplemental studies to further delineate and assess tar deposits in conformity with the MA DEP's guidance letter.

In 2010, HWP delivered a report to the MA DEP describing the results of its site investigation studies and testing. Subsequent communications and discussions with the MA DEP have focused on the course of action to achieve resolution of these matters, and are ongoing.

The $2.4 million reserve balance as of December 31, 2011 represents estimated costs that HWP considers probable over the remaining life of the project, including testing and related costs in the near term and field activities to be agreed upon with the MA DEP, further studies and long-term monitoring that are expected to be required by the MA DEP, and certain soft tar remediation activities. Various factors could affect management's estimates and require an increase to the reserve, which would be reflected as a charge to Net Income. Although a material increase to the reserve is not presently anticipated, management cannot reasonably estimate potential additional investigation or remediation costs because these costs would depend on, among other things, the nature, extent and timing of additional investigation and remediation that may be required by the MA DEP.

CERCLA: CERCLA and its amendments or state equivalents impose joint and several strict liabilities, regardless of fault, upon generators of hazardous substances resulting in removal and remediation costs and environmental damages. Liabilities under these laws can be material and in some instances may be imposed without regard to fault or for past acts that may have been lawful at the time they occurred. Of the total sites included in the remediation and long-term monitoring phase, 6 sites (4 for PSNH, 2 for CL&P and 1 for WMECO) are superfund sites under CERCLA for which the Company has been notified that it is a potentially responsible party but for which the site assessment and remediation are not being managed by the Company. As of December 31, 2011, a liability of $0.7 million ($0.3 million for CL&P and $0.4 million for PSNH) accrued on these sites represents management's best estimate of its potential remediation costs with respect to these superfund sites.

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

B. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of significant long-term contractual arrangements as of
December 31, 2011 are as follows:

NU

(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Totals**
Supply/Stranded Cost Contracts/Obligations	$ 260.9	$ 239.5	$ 193.6	$ 174.8	$ 179.0	$ 649.4	$ 1,697.2
Renewable Energy Contracts	11.4	60.0	175.6	177.9	189.1	2,955.8	3,569.8
Peaker CfDs	70.5	78.2	76.1	72.1	72.1	360.2	729.2
Natural Gas Procurement Contracts	68.1	55.6	52.0	36.8	31.7	73.3	317.5

Coal, Wood and Other Contracts	135.1	33.6	21.0	2.4	1.9	19.3	213.3
PNGTS Pipeline Commitments	3.1	3.1	3.1	3.1	3.1	6.7	22.2
Transmission Support Commitments	21.3	20.2	18.8	18.6	16.1	64.4	159.4
Yankee Companies Billings	27.3	27.8	27.2	22.4	-	-	104.7
Select Energy Purchase Agreements	15.8	18.2	-	-	-	-	34.0
Totals	$ 613.5	$ 536.2	$ 567.4	$ 508.1	$ 493.0	$ 4,129.1	$ 6,847.3

CL&P

(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Totals**
Supply/Stranded Cost Contracts/Obligations	$ 175.3	$ 169.4	$ 150.0	$ 145.6	$ 159.6	$ 595.3	$ 1,395.2
Renewable Energy Contracts	5.9	45.8	106.6	107.9	108.6	1,584.7	1,959.5
Peaker CfDs	70.5	78.2	76.1	72.1	72.1	360.2	729.2
Transmission Support Commitments	12.2	11.5	10.8	10.7	9.2	36.9	91.3
Yankee Companies Billings	18.7	19.1	18.7	15.8	-	-	72.3
Totals	$ 282.6	$ 324.0	$ 362.2	$ 352.1	$ 349.5	$ 2,577.1	$ 4,247.5

PSNH

(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Totals**
Supply/Stranded Cost Contracts/Obligations	$ 85.6	$ 70.1	$ 43.6	$ 29.2	$ 19.4	$ 54.1	$ 302.0
Renewable Energy Contracts	5.1	5.1	59.8	60.7	70.9	1,263.3	1,464.9
Coal, Wood and Other Contracts	135.1	33.6	21.0	2.4	1.9	19.3	213.3
PNGTS Pipeline Commitments	3.1	3.1	3.1	3.1	3.1	6.7	22.2
Transmission Support Commitments	6.6	6.3	5.8	5.7	5.0	19.8	49.2
Yankee Companies Billings	3.4	3.5	3.3	2.3	-	-	12.5
Totals	$ 238.9	$ 121.7	$ 136.6	$ 103.4	$ 100.3	$ 1,363.2	$ 2,064.1

WMECO

(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Totals**
Renewable Energy Contracts	$ 0.4	$ 9.1	$ 9.2	$ 9.3	$ 9.6	$ 107.8	$ 145.4
Transmission Support Commitments	2.5	2.4	2.2	2.2	1.9	7.7	18.9
Yankee Companies Billings	5.2	5.2	5.2	4.3	-	-	19.9
Totals	$ 8.1	$ 16.7	$ 16.6	$ 15.8	$ 11.5	$ 115.5	$ 184.2

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Supply/Stranded Cost Contracts/Obligations: CL&P, PSNH and WMECO have various IPP contracts or purchase obligations for electricity, including payment obligations resulting from the buydown of electricity purchase contracts. Excluding renewable and CfD contracts, which are discussed below, such contracts extend through 2024 for CL&P. At PSNH such contracts extend through 2023. The total cost of purchases and obligations under these contracts/obligations amounted to $132.2 million ($91.1 million for CL&P, $40.8 million for PSNH, and $0.3 million for WMECO) in 2011, $196.2 million ($151.3 million for CL&P, $42.6 million for PSNH, and $2.3 million for WMECO) in 2010, and $205.3 million ($173.1 million for CL&P, $29.8 million for PSNH, and $2.4 million for WMECO) in 2009.

In addition, CL&P and UI have entered into four CfDs for a total of approximately 787 MW of capacity with three generation projects being built or modified and one demand response project. The capacity CfDs extend through 2026 and obligate the utilities to pay the difference between a set price and the value that the projects receive in the ISO-NE markets. The contracts have terms of up to 15 years beginning in 2009 and are subject to a sharing agreement with UI, whereby UI will share 20 percent of the costs and benefits of these contracts. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers. The information in the table above includes 100 percent of the payments projected as of December 31, 2011 under the contracts entered into by CL&P and 80 percent of the payments projected under the contracts entered into by UI. The amounts of these payments are subject to changes in capacity and forward reserve prices that the projects receive in the ISO-NE capacity markets. The total cost incurred from these contracts amounted to $23.8 million in 2011.

The contractual obligations table does not include contractual commitments related to CL&P's SS or LRS or WMECO's default service, both of which represent contractual commitments that are conditional upon CL&P and WMECO customers' use of energy, and PSNH's short-term power supply management.

Renewable Energy Contracts: CL&P has entered into various agreements to purchase energy, capacity and renewable energy credits from renewable energy facilities. Amounts payable under these contracts are subject to a sharing agreement with UI, whereby UI will share approximately 20 percent of the costs and benefits of these contracts. In addition, UI has entered into contracts that are subject to this cost sharing agreement under which CL&P will share in approximately 80 percent of the costs and benefits of the contract. The information in the table above includes 100 percent of the payments projected under the contracts entered into by CL&P and 80 percent of the payments projected under the contracts entered into by UI. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers. CL&P s renewable energy contracts have terms ranging between 15 and 20 years. PSNH has supply contracts for the purchase of electricity from renewable suppliers, which extend through 2033. WMECO s contract to purchase electricity from a renewable supplier has a term of 15 years.

Peaker CfDs: In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by the PURA (Peaker CfDs). These units will have a total of approximately 500 MW of peaking capacity. As directed by the PURA, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The information in the table above includes 100 percent of the estimated payments projected under the contracts, before reimbursement from UI under the sharing agreement. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. CL&P's portion of the amounts paid or received under the Peaker CfDs will be recoverable from or refunded to CL&P's customers. The total cost incurred from these contracts amounted to $40.2 million in 2011 and $10 million in 2010.

Natural Gas Procurement Contracts: Yankee Gas has entered into long-term contracts for the purchase of natural gas in the normal course of business as part of its portfolio of supplies. These contracts extend through 2022. The total cost of Yankee Gas' procurement portfolio, including these contracts, amounted to $191.7 million in 2011, $209.5 million in 2010 and $236.3 million in 2009.

Coal, Wood and Other Contracts: PSNH has entered into various arrangements for the purchase of wood, coal and the transportation services for fuel supply for its electric generating assets. PSNH's fuel and natural gas costs, excluding emissions allowances, amounted to approximately $110.5 million in 2011, $168.3 million in 2010 and $156.7 million in 2009.

PNGTS Pipeline Commitments: PSNH has a contract for capacity on the Portland Natural Gas Transmission System (PNGTS) pipeline that extends through 2019. The cost under this contract amounted to $2.7 million in 2011, $2.8 million in 2010 and $1.6 million in 2009. These costs are not recovered from PSNH's customers.

Transmission Support Commitments: Along with other New England utilities, CL&P, PSNH and WMECO entered into agreements in 1985 to support transmission and terminal facilities that were built to import electricity from the Hydro-Québec system in Canada. CL&P, PSNH and WMECO are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual operation and maintenance expenses and capital costs of those facilities. CL&P, PSNH and WMECO's total cost of these agreements amounted to $10.3 million, $5.6 million and $2.2 million, respectively, in 2011, $10.8 million, $5.8 million and $2.3 million, respectively, in 2010, and $10.7 million, $5.7 million and $2.2 million, respectively, in 2009 ($18.1 million in 2011, $18.9 million in 2010 and $18.6 million in 2009 in the aggregate for NU).

Yankee Companies Billings: CL&P, PSNH and WMECO have significant decommissioning and plant closure cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. CL&P s, PSNH s and WMECO's total cost of these billings amounted to $18.3 million, $3.3 million and $5 million, respectively, in 2011, $22.7 million, $4.1 million and $6.2 million, respectively, in 2010, and $18.2 million, $3.7 million and $5 million, respectively, in 2009 ($26.6 million in 2011, $33 million in 2010 and $26.9 million in 2009 in the aggregate for NU).

See Note 12C, Commitments and Contingencies - Deferred Contractual Obligations, to the consolidated financial statements for information regarding the collection of the Yankee Companies' decommissioning costs.

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

C.

Deferred Contractual Obligations

CL&P, PSNH and WMECO have decommissioning and plant closure cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates.

CL&P, PSNH and WMECO's percentage share of the obligations to support the Yankee Companies under FERC-approved rate tariffs is the same as their respective ownership percentages in the Yankee Companies. For further information on the ownership percentages, see Note 1K, Summary of Significant Accounting Policies - Equity Method Investments, to the consolidated financial statements.

The Yankee Companies are currently collecting amounts that management believes are adequate to recover the remaining decommissioning and closure cost estimates for the respective plants. Management believes 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 (Yankee companies) filed separate complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002.

In December 2006, the DOE appealed the ruling, and the Yankee Companies filed cross-appeals. 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.

On September 7, 2010, the trial court issued its decision following remand, and judgment on the decision was entered on September 9, 2010. The judgment awarded CYAPC $39.7 million, YAEC $21.2 million and MYAPC $81.7 million. The DOE filed an appeal and the Yankee Companies cross-appealed on November 8, 2010. Briefs were filed and oral arguments in the appeal of the remanded case occurred on November 7, 2011. If the Court follows its previous schedule, a decision could be handed down within six months of the argument (second quarter 2012). Interest on the judgments does not start to accrue until all appeals have been decided and/or all appeal periods have expired without appeals being filed. 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 each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001 and 2002. On November 18, 2011, the court ordered the record closed in the YAEC case, and closed the record in the CYAPC and MYAPC cases subject to a limited opportunity of the government to reopen the records for further limited proceedings. The parties post-trial briefs will be filed during the first quarter of 2012 with a decision to come thereafter.

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 the Yankee Companies may obtain from the DOE on this matter. However, NU believes that any net settlement proceeds it receives would be incorporated into FERC-approved recoveries, which would be passed on to its customers through reduced charges.

D.

Guarantees and Indemnifications

NU parent provides credit assurances on behalf of its subsidiaries, including CL&P, PSNH and WMECO, in the form of guarantees and LOCs in the normal course of business.

NU provided guarantees and various indemnifications on behalf of external parties as a result of the sales of former subsidiaries of NU Enterprises, with maximum exposures either not specified or not material.

NU also issued a guaranty for the benefit of Hydro Renewable Energy under which, beginning at the time the Northern Pass Transmission line goes into commercial operation, NU will guarantee the financial obligations of NPT under the TSA in an amount not to exceed $18.8 million. NU's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations.

Management does not anticipate a material impact to Net Income to result from these various guarantees and indemnifications.

The following table summarizes NU's guarantees of its subsidiaries, including CL&P, PSNH and WMECO, as of December 31, 2011:

Subsidiary	**Description**		**Maximum Exposure (in millions)**	**Expiration Dates**
Various	Surety Bonds and Performance Guarantees	$	23.6	2012-2013 (1)
CL&P, PSNH and Select Energy	Letters of Credit	$	17.9	March 2012 - December 2012
NUSCO and RRR	Lease Payments for Vehicles and Real Estate	$	22.5	2019 and 2024
NU Enterprises	Surety Bonds, Insurance Bonds and Performance Guarantees	$	92.1 (2)	(2)

(1)

Surety bond expiration dates reflect bond termination dates, the majority of which will be renewed or extended.

(2)

The maximum exposure includes $23.5 million related to performance guarantees on wholesale purchase contracts, which expire in 2013, assuming purchase contracts guaranteed have no value; however, actual exposures vary with underlying commodity prices. The maximum exposure also includes $15.7 million related to a performance guarantee for which no maximum exposure is specified in the agreement. The maximum exposure was calculated as of December 31, 2011 based on limits of the liability contained in the underlying service contract and assumes that NU Enterprises will perform under that contract through its expiration in 2020. Also included in the maximum exposure is $1.2 million related to insurance bonds with no expiration date that are billed annually on their anniversary date. The remaining $51.7 million of maximum exposure relates to surety bonds covering ongoing projects, which expire upon project completion.

CL&P, PSNH and WMECO do not guarantee the performance of third parties.

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

E.

Exposure Regarding Complaint on FERC Base ROE

On September 30, 2011, several New England state attorneys general, state regulatory commissions, consumer advocates and other parties filed a joint complaint with the FERC under Sections 206 and 306 of the Federal Power Act alleging that the base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by New England transmission owners, including CL&P, PSNH and WMECO, is unjust and unreasonable. The complainants asserted that the current 11.14 percent rate, which became effective in 2006, is excessive due to changes in the capital markets and are seeking an order to reduce the rate to 9.2 percent, effective September 30, 2011.

On October 20, 2011, the New England transmission owners responded to the complaint, asking FERC to dismiss the complaint on the basis that the complainants failed to carry their burden of proof under Section 206 of the Federal Power Act to demonstrate that the existing base ROE is unjust and unreasonable. The New England transmission owners included testimony and analysis reflecting a base ROE of 11.2 percent using FERC s methodology and precedents, which they believe demonstrates that the current base ROE of 11.14 percent remains just and reasonable.

Although additional testimony was submitted by the complainants and the New England transmission owners in November and December 2011, the FERC has not yet issued an order in this proceeding and management cannot predict when this proceeding will be concluded, the outcome of this proceeding, or its impact on CL&P, PSNH, or WMECO s financial position, results of operations or cash flows.

F.

Litigation and Legal Proceedings

NU, including CL&P, PSNH and WMECO, are involved in legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, which involve management's assessment to determine the probability of whether a loss will occur and, if probable, its best estimate of probable loss. The Company records and discloses losses when these losses are probable and reasonably estimable, discloses matters when losses are probable but not estimable or reasonably possible, and expenses legal costs related to the defense of loss contingencies as incurred.

13.

LEASES

Various NU subsidiaries, including CL&P, PSNH and WMECO, have entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, and office space. In addition, CL&P, PSNH and WMECO incur costs associated with leases entered into by NUSCO and RRR. These costs are included below in CL&P, PSNH and WMECO's operating lease payments charged to expense and amounts capitalized as well as future operating lease payments from 2012 through 2016 and thereafter. These amounts are eliminated on an NU consolidated basis. The provisions of these lease agreements generally contain renewal options. Certain lease agreements contain payments impacted by the commercial paper rate plus a credit spread or the consumer price index.

For the years ended December 31, 2011, 2010 and 2009, rental payments made on capital leases, interest included in capital lease payments, and capital lease asset amortization were as follows:

	Rental Payments			Interest			Asset Amortization		
(Millions of Dollars)	NU	CL&P	PSNH	NU	CL&P	PSNH	NU	CL&P	PSNH
2011	$ 2.7	$ 2.0	$ 0.6	$ 1.7	$ 1.5	$ 0.2	$ 1.0	$ 0.5	$ 0.4
2010	2.5	1.9	0.5	1.8	1.5	0.3	0.7	0.4	0.2
2009	2.6	1.9	0.5	1.9	1.6	0.3	0.6	0.3	0.2

For the years ended December 31, 2011, 2010 and 2009, operating lease rental payments charged to expense and the capitalized portion of operating lease payments were as follows:

	Expensed				Capitalized			
(Millions of Dollars)	NU	CL&P	PSNH	WMECO	NU	CL&P	PSNH	WMECO
2011	$ 8.4	$ 8.3	$ 2.1	$ 2.8	$ 1.4	$ 0.8	$ 0.1	$ 0.1
2010	11.9	10.0	2.2	2.6	4.8	3.8	0.1	0.1
2009	18.1	12.8	3.9	3.4	9.7	6.1	1.5	1.1

Future minimum rental payments to external third parties excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, as of December 31, 2011 are as follows:

Capital Leases

(Millions of Dollars)	NU	CL&P	PSNH
2012	$ 3.0	$ 2.3	$ 0.6
2013	2.6	2.1	0.5
2014	2.2	1.9	0.2
2015	2.2	1.9	0.2
2016	2.0	1.9	0.1
Thereafter	9.5	9.4	-
Future minimum lease payments	21.5	19.5	1.6
Less amount representing interest	9.1	8.8	0.3
Present value of future minimum lease payments	$ 12.4	$ 10.7	$ 1.3

Operating Leases

(Millions of Dollars)	NU	CL&P	PSNH	WMECO
2012	$ 7.7	$ 3.2	$ 1.2	$ 2.6
2013	6.9	2.8	1.0	2.5
2014	4.9	2.6	0.8	0.9
2015	4.3	2.6	0.8	0.5
2016	4.3	2.6	0.8	0.4
Thereafter	16.6	12.0	2.3	1.3
Future minimum lease payments	$ 44.7	$ 25.8	$ 6.9	$ 8.2

CL&P entered into certain contracts for the purchase of energy that qualify as leases. These contracts do not have minimum lease payments and therefore are not included in the tables above. However, such contracts have been included in the contractual obligations table in Note 12B, Commitments and Contingencies - Long-Term Contractual Arrangements, to the consolidated financial statements.

14.

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of CL&P's preferred stock is based upon pricing models that incorporate interest rates and other market factors, valuations or trades of similar securities and cash flow projections. The fair value of fixed-rate long-term debt securities and RRBs is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions, credit ratings of the respective companies and treasury benchmark yields. Adjustable rate securities are assumed to have a fair value equal to their carrying value. Carrying amounts and estimated fair values are as follows:

	As of December 31, 2011							
	NU		CL&P		PSNH		WMECO	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 105.1	$ 116.2	$ 105.1	$ -	$ -	$ -	$ -
Long-Term Debt	4,950.7	5,517.0	2,587.8	2,987.1	999.5	1,075.2	501.1	539.8
Rate Reduction Bonds	112.3	116.8	-	-	85.4	88.8	26.9	28.1

	As of December 31, 2010							
	NU		CL&P		PSNH		WMECO	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 93.7	$ 116.2	$ 93.7	$ -	$ -	$ -	$ -
Long-Term Debt	4,692.4	5,043.8	2,587.5	2,816.7	837.3	871.4	401.0	417.0
Rate Reduction Bonds	181.6	193.3	-	-	138.2	146.9	43.3	46.4

Derivative Instruments: NU, including CL&P, PSNH and WMECO, holds various derivative instruments that are carried at fair value. For further information, see Note 4, Derivative Instruments, to the consolidated financial statements.

Other Financial Instruments: Investments in marketable securities are carried at fair value on the accompanying consolidated balance sheets. For further information, see Note 1I, Summary of Significant Accounting Policies - Fair Value Measurements, and Note 5, Marketable Securities, to the consolidated financial statements.

The carrying value of other financial instruments included in current assets and current liabilities, including cash and cash equivalents and special deposits, approximates their fair value due to the short-term nature of these instruments.

15.

PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION (CL&P)

CL&P's charter authorizes it to issue up to 9 million shares of preferred stock ($50 par value per share) of which 2,324,000 shares were outstanding as of December 31, 2011 and 2010. CL&P amended its charter on January 3, 2012 to remove references to various series of preferred stock, including the Class A preferred stock, which are no longer outstanding. There were no Class A preferred shares outstanding as of December 31, 2011 and 2010. The issuance of additional preferred shares would be subject to approval by the PURA.

Preferred stockholders have liquidation rights equal to the par value of the preferred stock, which they would receive in preference to any distributions to any junior stock. Were there to be a shortfall, all preferred stockholders would share ratably in available liquidation assets. Details of preferred stock not subject to mandatory redemption are as follows (in millions except in redemption price and shares):

Description			December 31, 2011 Redemption Price	Shares Outstanding as of December 31, 2011 and 2010	As of December 31, 2011	As of December 31, 2010
$	1.90	Series of 1947	$ 52.50	163,912	$ 8.2	$ 8.2
$	2.00	Series of 1947	$ 54.00	336,088	16.8	16.8
$	2.04	Series of 1949	$ 52.00	100,000	5.0	5.0
$	2.20	Series of 1949	$ 52.50	200,000	10.0	10.0
	3.90 %	Series of 1949	$ 50.50	160,000	8.0	8.0
$	2.06	Series E of 1954	$ 51.00	200,000	10.0	10.0
$	2.09	Series F of 1955	$ 51.00	100,000	5.0	5.0
	4.50 %	Series of 1956	$ 50.75	104,000	5.2	5.2
	4.96 %	Series of 1958	$ 50.50	100,000	5.0	5.0
	4.50 %	Series of 1963	$ 50.50	160,000	8.0	8.0
	5.28 %	Series of 1967	$ 51.43	200,000	10.0	10.0
$	3.24	Series G of 1968	$ 51.84	300,000	15.0	15.0
	6.56 %	Series of 1968	$ 51.44	200,000	10.0	10.0
Totals				2,324,000	$ 116.2	$ 116.2

Dividends totaling $5.6 million for 2011, $6.1 million for 2010 and $5.6 million for 2009 were declared and dividends of $5.6 million were paid to the preferred stockholders in 2011, 2010 and 2009.

16.

ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

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

(Millions of Dollars)	As of December 31,	
NU	**2011**	**2010**
Qualified Cash Flow Hedging Instruments	$ (18.4)	$ (4.2)
Unrealized Gains on Other Securities	1.1	0.6
Pension, SERP and PBOP Benefits	(53.4)	(39.8)
Accumulated Other Comprehensive Loss	$ (70.7)	$ (43.4)
CL&P		
Qualified Cash Flow Hedging Instruments	$ (2.3)	$ (2.7)
Unrealized Gains on Other Securities	-	-
Accumulated Other Comprehensive Loss	$ (2.3)	$ (2.7)
PSNH		
Qualified Cash Flow Hedging Instruments	$ (10.9)	$ (0.6)
Unrealized Gains on Other Securities	0.1	-
Accumulated Other Comprehensive Loss	$ (10.8)	$ (0.6)
WMECO		
Qualified Cash Flow Hedging Instruments	$ (4.2)	$ (0.1)
Unrealized Gains on Other Securities	-	-
Accumulated Other Comprehensive Loss	$ (4.2)	$ (0.1)

Qualified cash flow hedging items impacting Net Income in the tables above represent amounts that were reclassified from Accumulated Other Comprehensive Income/(Loss) into Net Income for interest rate swap agreements. For the year ended December 31, 2011 amounts were as follows:

	For the Year Ended December 31, 2011		
(Millions of Dollars)	**NU**	**PSNH**	**WMECO**
Balance as of January 1, 2011	$ (4.2)	$ (0.6)	$ (0.1)
Hedged Transactions Recognized into Earnings	0.7	0.5	0.1
Cash Flow Hedging Transactions Entered into for the Year	(14.9)	(10.8)	(4.2)
Net Change Associated with Hedging Transactions	(14.2)	(10.3)	(4.1)
Total Fair Value Adjustments Included in Accumulated Other Comprehensive Loss	$ (18.4)	$ (10.9)	$ (4.2)

For further information regarding cash flow hedging transactions, see Note 4, Derivative Instruments, to the consolidated financial statements.

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

(Millions of Dollars)						
NU		**2011**		**2010**		**2009**
Qualified Cash Flow Hedging Instruments	$	9.5	$	(0.2)	$	(0.2)
Change in Unrealized Gains/(Losses) on Other Securities		(0.4)		(0.2)		0.7
Pension, SERP and PBOP Benefits		7.9		-		2.9
Total	$	17.0	$	(0.4)	$	3.4
CL&P						
Qualified Cash Flow Hedging Instruments	$	(0.3)	$	(0.3)	$	(0.3)
PSNH						
Qualified Cash Flow Hedging Instruments	$	7.0	$	(0.1)	$	-
WMECO						
Qualified Cash Flow Hedging Instruments	$	2.7	$	-	$	0.1

It is estimated that a charge of $2.2 million will be reclassified from Accumulated Other Comprehensive Income/(Loss) as a decrease to earnings over the next 12 months as a result of amortization of the interest rate swap agreements, which have been settled. Included in this amount are estimated charges of $0.4 million, $1.2 million and $0.3 million for CL&P, PSNH and WMECO, respectively. As of December 31, 2011, it is estimated that a pre-tax amount of $8.7 million included in the Accumulated Other Comprehensive Income/(Loss) balance will be reclassified as a decrease to Net Income over the next 12 months related to Pension, SERP and PBOP adjustments for NU.

17.

DIVIDEND RESTRICTIONS

NU parent's ability to pay dividends may be affected by certain state statutes, the ability of its subsidiaries to pay common dividends and the leverage restriction tied to its consolidated total debt to total capitalization ratio requirement in its revolving credit agreement.

CL&P, PSNH and WMECO are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds properly included in its capital account. Management believes that this Federal Power Act restriction, as applied to CL&P, PSNH and WMECO, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from retained earnings. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas. Such state law restrictions do not restrict payment of dividends from retained earnings or net income. CL&P, PSNH, WMECO and Yankee Gas also have a revolving credit agreement that imposes leverage restrictions including consolidated total debt to total capitalization ratio requirements. The Retained Earnings balances subject to these leverage restrictions are $1.652 billion for NU, $735.9 million for CL&P, $388.9 million for PSNH and $115.5 million for WMECO as of December 31, 2011. PSNH is further required to reserve an additional amount under its FERC hydroelectric license conditions. As of December 31, 2011, approximately $11.9 million of PSNH's Retained Earnings is subject to restriction under its FERC hydroelectric license conditions. As of December 31, 2011, NU, CL&P, PSNH, WMECO and Yankee Gas were in compliance with all such provisions of its credit agreement that may restrict the payment of dividends.

18.

COMMON SHARES

The following table sets forth the NU common shares and the shares of CL&P, PSNH and WMECO common stock authorized and issued as of December 31, 2011 and 2010 and the respective par values:

			Shares			
			Authorized As of December 31,		**Issued As of December 31,**	
		Per Share Par Value	**2011**	**2010**	**2011**	**2010**
NU	$	5	380,000,000	225,000,000	196,052,770	195,781,740
CL&P	$	10	24,500,000	24,500,000	6,035,205	6,035,205
PSNH	$	1	100,000,000	100,000,000	301	301
WMECO	$	25	1,072,471	1,072,471	434,653	434,653

As of December 31, 2011 and 2010, 18,894,078 and 19,333,659 NU common shares were held as treasury shares, respectively.

On March 4, 2011, NU's shareholders approved an increase in authorized shares from 225,000,000 to 380,000,000 in connection with the consummation of the NU-NSTAR pending merger.

19. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS (NU)

A summary of the changes in Common Shareholders' Equity and Noncontrolling Interests of NU is as follows:

	For the Year Ended December 31, 2011			
(Millions of Dollars)	**Common Shareholders' Equity**	**Noncontrolling Interest**	**Total Equity**	**Preferred Stock Not Subject to Mandatory Redemption**
Balance, Beginning of Year	$ 3,811.2	$ 1.5	$ 3,812.7	$ 116.2
Net Income	400.5	-	400.5	-
Dividends on Common Shares	(195.6)	-	(195.6)	-
Dividends on Preferred Stock	(5.6)	-	(5.6)	(5.6)
Issuance of Common Shares	5.9	-	5.9	-
Contributions to NPT	-	1.2	1.2	-
Other Transactions, Net	23.9	-	23.9	-
Net Income Attributable to Noncontrolling Interests	(0.3)	0.3	-	5.6
Other Comprehensive Loss (Note 16)	(27.3)	-	(27.3)	-
Balance, End of Year	$ 4,012.7	$ 3.0	$ 4,015.7	$ 116.2

	For the Years Ended December 31, 2010				2009	
(Millions of Dollars)	**Common Shareholders' Equity**	**Noncontrolling Interest**	**Total Equity**	**Preferred Stock Not Subject to Mandatory Redemption**	**Total Equity**	**Preferred Stock Not Subject to Mandatory Redemption**
Balance, Beginning of Year	$ 3,577.9	$ -	$ 3,577.9	$ 116.2	$ 3,020.3	$ 116.2
Net Income	394.1	-	394.1	-	335.6	-
Dividends on Common Shares	(181.7)	-	(181.7)	-	(162.8)	-
Dividends on Preferred Stock	(6.1)	-	(6.1)	(6.1)	(5.6)	(5.6)
Issuance of Common Shares	7.4	-	7.4	-	389.7	-
Capital Stock Expenses, Net	(0.3)	-	(0.3)	-	(12.5)	-
Contributions to NPT	-	1.4	1.4	-	-	-
Other Transactions, Net	19.9	-	19.9	-	18.7	-
Net Income Attributable to Noncontrolling Interests	(0.1)	0.1	-	6.1	-	5.6
Other Comprehensive Income/(Loss) (Note 16)	0.1	-	0.1	-	(5.5)	-
Balance, End of Year	$ 3,811.2	$ 1.5	$ 3,812.7	$ 116.2	$ 3,577.9	$ 116.2

For the years ended December 31, 2011, 2010, and 2009, there was no change in NU parent's 100 percent ownership of the common equity of CL&P.

20.

EARNINGS PER SHARE (NU)

EPS is computed based upon the monthly weighted average number of common shares outstanding, excluding unallocated ESOP shares, during each period. Diluted EPS is computed on the basis of the monthly weighted average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common shares. The computation of diluted EPS excludes the effect of the potential exercise of share awards when the average market price of the common shares is lower than the exercise price of the related awards during the period. These outstanding share awards are not included in the computation of diluted EPS because the effect would have been antidilutive. For the years ended December 31, 2011, 2010 and 2009, there were 4,314, 1,578 and 17,637 share awards, respectively, excluded from the computation as these awards were antidilutive.

The following table sets forth the components of basic and diluted EPS.

(Millions of Dollars, except share information)		**2011**		**2010**		**2009**
Net Income Attributable to Controlling Interests	$	394.7	$	387.9	$	330.0
Weighted Average Common Shares Outstanding:						
Basic		177,410,167		176,636,086		172,567,928
Dilutive Effect		394,401		249,301		149,318
Diluted		177,804,568		176,885,387		172,717,246
Basic EPS	$	2.22	$	2.20	$	1.91
Diluted EPS	$	2.22	$	2.19	$	1.91

RSUs and performance shares are included in basic weighted average common shares outstanding as of the date that all necessary vesting conditions have been satisfied. The dilutive effect of unvested RSUs and performance shares is calculated using the treasury stock method. Assumed proceeds of the units under the treasury stock method consist of the remaining compensation cost to be recognized and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the units (the difference between the market value of the average units outstanding for the period, using the average market price during the period, and the grant date market value).

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

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

21.

SEGMENT INFORMATION

Presentation: NU is organized between the Regulated companies' segments and Other based on a combination of factors, including the characteristics of each business' products and services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. Cash flows for total investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income.

The Regulated companies' segments include the electric distribution segment, the natural gas distribution segment and the electric transmission segment. The electric distribution segment includes the generation activities of PSNH and WMECO. The Regulated companies' segments represented substantially all of NU's total consolidated revenues for the years ended December 31, 2011, 2010 and 2009.

Other in the tables below primarily consists of 1) the results of NU parent, which includes other income related to the equity in earnings of NU parent's subsidiaries and interest income from the NU Money Pool, which are both eliminated in consolidation, and interest income and expense related to the cash and debt of NU parent, respectively, 2) the revenues and expenses of NU's service companies, most of which are eliminated in consolidation, and 3) the results of other subsidiaries, which are comprised of NU Enterprises, RRR (a real estate subsidiary), the non-energy-related subsidiaries of Yankee and the remaining operations of HWP.

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

NU's segment information for the years ended December 31, 2011, 2010 and 2009, with the distribution segment segregated between electric and natural gas, is as follows:

	For the Year Ended December 31, 2011					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 3,343.1	$ 430.8	$ 635.4	$ 541.3	$ (484.9)	$ 4,465.7
Depreciation and Amortization	(343.2)	(27.7)	(84.0)	(16.8)	2.5	(469.2)
Other Operating Expenses	(2,631.4)	(333.5)	(188.2)	(534.1)	484.9	(3,202.3)
Operating Income/(Loss)	368.5	69.6	363.2	(9.6)	2.5	794.2
Interest Expense	(123.8)	(21.0)	(76.7)	(33.7)	4.8	(250.4)
Interest Income	3.7	-	0.5	5.3	(5.3)	4.2
Other Income, Net	11.6	1.3	10.7	455.2	(455.3)	23.5
Income Tax (Expense)/Benefit	(67.6)	(18.2)	(95.6)	14.3	(3.9)	(171.0)
Net Income	192.4	31.7	202.1	431.5	(457.2)	400.5
Net Income Attributable to Noncontrolling Interests	(3.3)	-	(2.5)	-	-	(5.8)
Net Income Attributable to Controlling Interests	$ 189.1	$ 31.7	$ 199.6	$ 431.5	$ (457.2)	$ 394.7
Total Assets (as of)	$ 9,653.1	$ 1,511.3	$ 3,792.9	$ 6,618.0	$ (5,928.2)	$ 15,647.1
Cash Flows Used for Investments in Plant	$ 540.7	$ 98.2	$ 388.9	$ 48.9	$ -	$ 1,076.7

	For the Year Ended December 31, 2010					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 3,802.0	$ 434.3	$ 625.6	$ 521.6	$ (485.3)	$ 4,898.2
Depreciation and Amortization	(506.7)	(23.8)	(86.7)	(15.8)	3.8	(629.2)
Other Operating Expenses	(2,919.6)	(340.0)	(192.1)	(505.4)	488.0	(3,469.1)
Operating Income	375.7	70.5	346.8	0.4	6.5	799.9
Interest Expense	(133.4)	(17.9)	(73.2)	(17.4)	4.6	(237.3)
Interest Income	0.7	-	1.8	5.3	(6.3)	1.5
Other Income, Net	24.4	0.8	14.3	436.4	(435.5)	40.4
Income Tax (Expense)/Benefit	(90.3)	(20.7)	(109.3)	11.0	(1.1)	(210.4)
Net Income	177.1	32.7	180.4	435.7	(431.8)	394.1
Net Income Attributable to Noncontrolling Interests	(3.6)	-	(2.6)	-	-	(6.2)
Net Income Attributable to Controlling Interests	$ 173.5	$ 32.7	$ 177.8	$ 435.7	$ (431.8)	$ 387.9
Total Assets (as of)	$ 8,910.1	$ 1,447.2	$ 3,434.0	$ 6,283.0	$ (5,601.7)	$ 14,472.6
Cash Flows Used for Investments in Plant	$ 560.1	$ 82.5	$ 239.2	$ 72.7	$ -	$ 954.5

	For the Year Ended December 31, 2009					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 4,358.4	$ 449.6	$ 577.9	$ 482.1	$ (428.6)	$ 5,439.4
Depreciation and Amortization	(431.5)	(26.8)	(71.0)	(13.4)	1.9	(540.8)
Other Operating Expenses	(3,604.6)	(368.1)	(170.9)	(435.9)	432.3	(4,147.2)
Operating Income	322.3	54.7	336.0	32.8	5.6	751.4
Interest Expense	(149.1)	(22.1)	(72.5)	(36.2)	6.3	(273.6)
Interest Income	4.5	-	1.0	7.7	(7.6)	5.6
Other Income, Net	24.0	0.3	7.6	371.6	(371.4)	32.1
Income Tax (Expense)/Benefit	(60.2)	(11.9)	(105.5)	0.1	(2.4)	(179.9)
Net Income	141.5	21.0	166.6	376.0	(369.5)	335.6
Net Income Attributable to Noncontrolling Interests	(3.3)	-	(2.3)	-	-	(5.6)
Net Income Attributable to Controlling Interests	$ 138.2	$ 21.0	$ 164.3	$ 376.0	$ (369.5)	$ 330.0
Cash Flows Used for Investments in Plant	$ 521.5	$ 54.8	$ 286.0	$ -	$ 45.8	$ 908.1

The information related to the distribution and transmission segments for CL&P, PSNH and WMECO for the years ended December 31, 2011, 2010, and 2009 is included below.

	CL&P - For the Years Ended December 31,								
	2011			2010			2009		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 2,065.3	$ 483.1	$ 2,548.4	$ 2,500.3	$ 498.8	$ 2,999.1	$ 2,954.6	$ 469.9	$ 3,424.5
Depreciation and Amortization	(158.7)	(64.2)	(222.9)	(355.5)	(67.6)	(423.1)	(330.3)	(58.4)	(388.7)
Other Operating Expenses	(1,722.7)	(139.6)	(1,862.3)	(1,942.4)	(146.0)	(2,088.4)	(2,441.7)	(129.0)	(2,570.7)
Operating Income	183.9	279.3	463.2	202.4	285.2	487.6	182.6	282.5	465.1
Interest Expense	(71.7)	(61.0)	(132.7)	(77.6)	(60.1)	(137.7)	(93.1)	(62.7)	(155.8)
Interest Income	2.4	0.4	2.8	1.9	1.5	3.4	2.7	0.8	3.5

Other Income, Net	2.5	4.4	6.9	14.6	8.6	23.2	16.2	6.1	22.3
Income Tax Expense	(21.1)	(68.9)	(90.0)	(43.6)	(88.8)	(132.4)	(31.1)	(87.7)	(118.8)
Net Income	$ 96.0	$ 154.2	$ 250.2	$ 97.7	$ 146.4	$ 244.1	$ 77.3	$ 139.0	$ 216.3
Total Assets (as of)	$ 6,161.0	$ 2,630.4	$ 8,791.4	$ 5,640.0	$ 2,615.2	$ 8,255.2			
Cash Flows Used for Investments in Plant	$ 303.2	$ 121.7	$ 424.9	$ 270.2	$ 110.1	$ 380.3	$ 270.8	$ 164.9	$ 435.7

PSNH - For the Years Ended December 31,

	2011			**2010**			**2009**		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 923.7	$ 89.3	$ 1,013.0	$ 951.0	$ 82.4	$ 1,033.4	$ 1,035.8	$ 73.8	$ 1,109.6
Depreciation and Amortization	(143.4)	(11.5)	(154.9)	(118.4)	(10.4)	(128.8)	(70.5)	(9.3)	(79.8)
Other Operating Expenses	(644.4)	(33.6)	(678.0)	(696.0)	(32.4)	(728.4)	(865.8)	(29.4)	(895.2)
Operating Income	135.9	44.2	180.1	136.6	39.6	176.2	99.5	35.1	134.6
Interest Expense	(36.2)	(7.9)	(44.1)	(38.6)	(8.5)	(47.1)	(39.8)	(6.7)	(46.5)
Interest Income/(Loss)	0.9	0.1	1.0	(1.7)	0.2	(1.5)	2.1	0.1	2.2
Other Income, Net	11.2	2.0	13.2	11.6	1.7	13.3	6.0	1.3	7.3
Income Tax Expense	(35.6)	(14.3)	(49.9)	(38.6)	(12.2)	(50.8)	(20.2)	(11.8)	(32.0)
Net Income	$ 76.2	$ 24.1	$ 100.3	$ 69.3	$ 20.8	$ 90.1	$ 47.6	$ 18.0	$ 65.6
Total Assets (as of)	$ 2,551.3	$ 565.2	$ 3,116.5	$ 2,388.4	$ 490.7	$ 2,879.1			
Cash Flows Used for Investments in Plant	$ 189.0	$ 52.8	$ 241.8	$ 252.2	$ 44.1	$ 296.3	$ 207.8	$ 58.6	$ 266.4

WMECO - For the Years Ended December 31,

	2011			**2010**			**2009**		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 354.4	$ 62.9	$ 417.3	$ 350.9	$ 44.3	$ 395.2	$ 368.2	$ 34.2	$ 402.4
	(41.1)	(8.2)	(49.3)	(32.9)	(8.6)	(41.5)	(30.8)	(3.2)	(34.0)

Depreciation and Amortization									
Other Operating Expenses	(264.6)	(15.0)	(279.6)	(281.3)	(13.8)	(295.1)	(297.3)	(12.5)	(309.8)
Operating Income	48.7	39.7	88.4	36.7	21.9	58.6	40.1	18.5	58.6
Interest Expense	(15.9)	(7.7)	(23.6)	(17.1)	(4.7)	(21.8)	(16.1)	(3.2)	(19.3)
Interest Income/(Loss)	0.4	-	0.4	0.4	0.2	0.6	(0.3)	-	(0.3)
Other Income/(Loss), Net	(2.1)	3.2	1.1	(1.8)	3.8	2.0	1.8	0.3	2.1
Income Tax Expense	(10.9)	(12.3)	(23.2)	(8.1)	(8.2)	(16.3)	(8.8)	(6.1)	(14.9)
Net Income	$ 20.2	$ 22.9	$ 43.1	$ 10.1	$ 13.0	$ 23.1	$ 16.7	$ 9.5	$ 26.2
Total Assets (as of)	$ 942.6	$ 560.3	$ 1,502.9	$ 884.2	$ 315.4	$ 1,199.6			
Cash Flows Used for									
Investments in Plant	$ 48.5	$ 189.5	$ 238.0	$ 37.6	$ 77.6	$ 115.2	$ 42.9	$ 62.5	$ 105.4

22.

VARIABLE INTEREST ENTITIES

The Company's variable interests outside of the consolidated group are not material and consist of contracts that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. NU holds variable interests in variable interest entities (VIEs) through agreements with certain entities that own single renewable energy or peaking generation power plants and with other independent power producers. NU does not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. Therefore, NU does not consolidate any power plant VIEs.

23.

QUARTERLY FINANCIAL DATA (UNAUDITED)

NU Consolidated Statements of Quarterly Financial Data	**Quarter Ended (a)**							
(Millions of Dollars, except per share information)		**March 31,**		**June 30,**		**September 30,**		**December 31,**
2011								
Operating Revenues	$	1,235.3	$	1,047.5	$	1,114.9	$	1,068.0
Operating Income		227.4		178.1		203.8		184.9
Net Income		115.6		78.7		91.4		114.8
Net Income Attributable to Controlling Interests		114.2		77.3		90.0		113.2
Basic and Diluted Earnings Per Common Share	$	0.64	$	0.44	$	0.51	$	0.64
2010								
Operating Revenues	$	1,339.4	$	1,111.4	$	1,243.3	$	1,204.1
Operating Income		226.7		178.3		199.6		195.3
Net Income		87.6		73.3		101.9		131.3
Net Income Attributable to Controlling Interests		86.2		71.9		100.5		129.3
Basic and Diluted Earnings Per Common Share	$	0.49	$	0.41	$	0.57	$	0.73

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

CL&P Consolidated Statements of Quarterly Financial Data	**Quarter Ended**							
(Millions of Dollars)		**March 31,**		**June 30,**		**September 30,**		**December 31,**
2011								
Operating Revenues	$	673.7	$	608.0	$	673.7	$	593.0

Operating Income		126.0		114.8		137.7		84.7
Net Income		64.3		52.6		66.5		66.8
2010								
Operating Revenues	$	795.0	$	707.9	$	789.2	$	707.0
Operating Income		125.5		106.2		131.4		124.6
Net Income		48.4		44.1		69.0		82.6

PSNH Consolidated Statements of Quarterly Financial Data	Quarter Ended							
(Millions of Dollars)	**March 31,**		**June 30,**		**September 30,**		**December 31,**	
2011								
Operating Revenues	$	269.5	$	240.2	$	259.6	$	243.7
Operating Income		46.9		37.9		48.5		46.8
Net Income		27.5		21.7		25.6		25.5
2010								
Operating Revenues	$	258.6	$	238.3	$	277.0	$	259.5
Operating Income		39.9		43.4		49.8		43.1
Net Income		15.8		21.6		28.8		23.9

WMECO Consolidated Statements of Quarterly Financial Data	Quarter Ended							
(Millions of Dollars)	**March 31,**		**June 30,**		**September 30,**		**December 31,**	
2011								
Operating Revenues	$	106.7	$	98.4	$	104.5	$	107.7
Operating Income		21.1		18.5		19.8		29.0
Net Income		10.0		8.2		8.4 (1)		16.5
2010								
Operating Revenues	$	100.2	$	92.5	$	103.7	$	98.8
Operating Income		16.4		14.3		14.9		13.1
Net Income		5.7		5.2		7.3		4.9

(1)

Distribution segment Net Income for the quarter ended September 30, 2011 decreased by $3.2 million, as compared to the quarter ended September 30, 2010, related to a pre-tax charge to establish a reserve of $5.3 million to reflect a wholesale billing adjustment, $4.3 million of which related to prior period amounts.

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 GAAP. 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, 2011.

Management, on behalf of NU, CL&P, PSNH and WMECO, evaluated the design and operation of the disclosure controls and procedures as of December 31, 2011 to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Securities Exchange Act of 1934 and the rules and regulations 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 Annual Report on Form 10-K. There are inherent limitations of disclosure controls and procedures, including the possibility of human error and the circumventing or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. 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 Securities Exchange Act of 1934 (i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and regulations 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 disclosures.

There have been no changes in internal controls over financial reporting for NU, CL&P, PSNH and WMECO during the quarter ended December 31, 2011 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, 2011, as this information has been previously disclosed in applicable reports on Form 8-K during the fourth quarter of 2011.

PART III

Item 10.

Directors, Executive Officers and Corporate Governance

The information in Item 10 is provided as of February 15, 2012 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

NU s Board of Trustees oversees the business affairs and management of Northeast Utilities. The Board currently consists of 11 Trustees, only one of whom, Charles W. Shivery, NU s Chairman of the Board, President and Chief Executive Officer, is a member of management. Trustees are elected at the Annual Meeting of Shareholders and hold office until the next annual meeting and until the succeeding Board of Trustees has been elected, and until at least a majority of the succeeding board is qualified to act.

Set forth below is each Trustee s name, age, date first elected as a Trustee, and a brief summary of his or her business experience, including the particular experience, qualifications, attributes or skills that led the Board to conclude that he or she should serve as a Trustee.

Richard H. Booth, Age: 64; Trustee since 2001. Since July 2009, Mr. Booth has served as Vice Chairman of Guy Carpenter & Company, LLC, a global reinsurance intermediary and a wholly owned subsidiary of Marsh & McLennan Companies, Inc. From June 2008 to March 2009, Mr. Booth served as a corporate officer, and from October 2008 to March 2009, as Vice Chairman, Transition Planning and Chief Administrative Officer, of American International Group, Inc., an insurance and financial services company. From January 2000 to March 2009, he served as Chairman and a director, and from January 2000 to July 2007, as President and Chief Executive Officer, of HSB Group, Inc., a specialty insurer and reinsurer. From January 2000 to March 2009, he served as Chairman and a director, and from January 2000 to July 2007, as Chief Executive Officer, of Hartford Steam Boiler Inspection and Insurance Company, a provider of insurance and engineering services and investments, formerly a wholly owned subsidiary of American International Group, Inc., which was sold to Munich Re effective March 31, 2009. He is a member of the American Institute of Certified Public Accountants, the Connecticut Society of CPAs, the Hartford Society of Financial Analysts and the CFA Institute. Mr. Booth is currently a member of the boards of Sun Life Financial Inc., WorldBusiness Capital LLC, the Florence Griswold Museum (Emeritus) and the National Association of Corporate Directors, Connecticut Chapter. He is a senior adviser to Century Capital Management. Mr. Booth received B.S. and M.S. degrees from the University of Hartford. He is a certified public accountant and a former member of the Financial Accounting Standards Advisory Council and its Steering Committee.

Mr. Booth has considerable senior executive level experience in business and management, including in particular strategic planning, capital and financial markets, accounting and financial reporting, credit markets and risk assessment, both in his current position as an executive officer of Guy Carpenter as well as in prior positions including Chairman of HSB Group and Chairman of Hartford Steam Boiler. He has served on the board of directors of numerous companies. In addition, Mr. Booth is a certified public accountant. Based on these skills and qualifications, coupled with his ties to the City of Hartford and the State of Connecticut, the Board of Trustees determined that Mr. Booth should serve as a Trustee.

John S. Clarkeson, Age: 69; Trustee since 2008. Mr. Clarkeson has served as the Chairman Emeritus of The Boston Consulting Group, Inc. since 2007. Previously, Mr. Clarkeson served as Co-Chairman of the Board of The Boston Consulting Group, Inc. from 2004 to 2007, Chairman of The Boston Consulting Group, Inc. from 1998 to 2003, and Chief Executive Officer and President from 1986 to 1997. He is a director of the Cabot Corporation, the past Chairman of the National Bureau of Economic Research, a trustee of the Educational Testing Service, a trustee emeritus of the Massachusetts General Physicians Organization, Inc., and a member of the INSEAD Advisory Council. Mr. Clarkeson received an A.B. degree magna cum laude from Harvard College, where he was a Harvard National Scholar, and an M.B.A. from Harvard Business School.

Mr. Clarkeson has significant senior executive level experience in business and management through his service as Chairman and CEO of The Boston Consulting Group as well as his service as a director of Cabot Corporation, where he chairs the governance committee and serves on the compensation and executive committees. He has served on the board of directors of numerous companies. He also has experience in budgeting, capital and financial markets, credit markets, and risk assessment. Based on these skills and qualifications, the Board of Trustees determined that Mr. Clarkeson should serve as a Trustee.

Cotton M. Cleveland, Age: 59; Trustee since 1992. Ms. Cleveland has been President of Mather Associates, a firm specializing in leadership and organizational development for business, public and nonprofit organizations, since 1981. She is a director of The National Grange Mutual Insurance Company and Ledyard National Bank. She was elected and served as the Moderator of the Town of New London, New Hampshire and the New London/Springfield Water Precinct from 2000 to 2010. Ms. Cleveland has formerly served on the board of the New Hampshire Center for Public Policy and as a director of Bank of Ireland First Holdings. Ms. Cleveland has also served as Chair, Vice Chair and member of the Board of Trustees of the University System of New Hampshire, as Co-Chair of the Governor s Commission on New Hampshire in the 21st Century, and as an incorporator for the New Hampshire Charitable Foundation. Ms. Cleveland received a B.S. magna cum laude from the University of New Hampshire, Whittemore School of Business and Economics. She is a certified and practicing Court Appointed Special Advocate (CASA) for abused and neglected children.

Ms. Cleveland founded and serves as president of her own consulting firm. She has experience serving on the board of directors of numerous companies. She also benefits from her policy-making level experience in education at the university level as the Chair, Vice Chair and member of the Board of Trustees of the University System of New Hampshire. In addition, she has policy-making level experience in financial and capital markets as a result of her service as a director of Ledyard National Bank and Bank of Ireland. Based on her skills and experience, combined with her ties to the State of New Hampshire, the Board of Trustees determined that Ms. Cleveland should serve as a Trustee.

Sanford Cloud, Jr., Age: 67; Trustee since 2000. Mr. Cloud has been Chairman and Chief Executive Officer of The Cloud Company, LLC, a real estate development and business investment firm, since 2005. Mr. Cloud is a past President and Chief Executive Officer of the National Conference for Community and Justice from 1994 to 2004, a former partner at the law firm of Robinson and Cole from 1993 to 1994, and served for two terms as a state senator of Connecticut. A former Vice President of Corporate Public Involvement of Aetna Inc. from 1986 to 1992. Mr. Cloud has served as a director of The Phoenix Companies, Inc. since 2001 and is currently a director of Ironwood Mezzanine Fund, L.P. He is also a director of the MetroHartford Alliance, Inc., The Connecticut Health Foundation and the University of Connecticut Medical Health Center. Mr. Cloud received a B.A. from Howard University, a J.D. cum laude from the Howard University Law School, and an M.A. in Religious Studies from the Hartford Seminary.

Mr. Cloud has significant policy-making level experience in business and financial affairs as a director of several publicly traded companies. He has served on the board of directors of numerous companies. Combined with his practice as a law firm partner, his political and governmental experience as a Connecticut state senator, and his significant ties to the City of Hartford and the State of Connecticut, the Board of Trustees determined that Mr. Cloud should serve as a Trustee.

John G. Graham, Age: 73; Trustee since 2003. From 1999 to 2006, Mr. Graham served as President and Chief Executive Officer and a director of UMICO Holdings, Inc. and UMI Insurance Company, both of Parsippany, New Jersey. From 1999 to 2005, he served as an Adjunct Professor of Law at Rutgers Law School, where he taught in the fields of the law of economic regulation, energy law and insurance law. From 1999 to 2003, Mr. Graham served as a consultant to various firms concerning utility industry strategic and restructuring issues. Mr. Graham has served as Senior Vice President and Chief Financial Officer of GPU, Inc., and Chief Financial Officer of its utility subsidiaries from 1987 to 1999, as a director (from 1982 to 1999), and former Chairman (from 1995 to 1998) of Nuclear Electric Insurance Limited, and as a director and member of audit, directors and compensation committees of Viatel, Inc. from 1998 to 2002, and as a director and audit committee chairman of Coho Energy, Inc. from 2000 to 2001. Mr. Graham received an A.B. cum laude from Upsala College and a J.D. magna cum laude from Rutgers Law School, Newark, New Jersey.

Mr. Graham has significant experience in the energy industry as a director and executive officer of several utilities and energy companies including GPU, Inc. He also has financial policy-making and accounting and financial reporting experience, and an understanding of finance and capital markets. He has served on the board of directors of numerous companies. He also has significant experience in education at the university level as a result of his work as a law professor teaching energy law and economic regulation. Based on his skills and experience, the Board of Trustees determined that Mr. Graham should serve as a Trustee.

Elizabeth T. Kennan, Age: 73; Lead Trustee since 1996; Trustee since 1980. Dr. Kennan has been President Emeritus of Mount Holyoke College since 1996 and a partner in Cambus-Kenneth Farm, a specialized horse and cattle breeder, since 2000. Dr. Kennan has served as President of Five Colleges, Incorporated, as a trustee of Notre Dame University, and as a member of the Folger Shakespeare Library Committee and the National Committee on Library Resources, and holds honorary degrees from a number of institutions. Dr. Kennan is a trustee of the National Trust for Historic Preservation and Centre College. She is Chairman of the Board of Shaker Village of Pleasant Hill. Dr. Kennan became a trustee of The Putnam Mutual Funds in January 2012 after having previously served as trustee from 1993 to 2010. She acted as interim Chairman of the Board of Northeast Utilities from January 1, 2004 to March 29, 2004. Dr. Kennan previously served as a director of The Talbots, Inc. from 1993 to 2005, a director of Bell Atlantic Corporation from 1997 to 2000, and a director of NYNEX Corporation from 1984 to 1997. Dr. Kennan received an A.B. summa cum laude from Mount Holyoke College, an M.A. from Oxford University (England), and a Ph.D. from the University of Washington.

Dr. Kennan has significant policy-making level experience in education at the university level as a result of her service as the President and President Emeritus of Mount Holyoke College, President of Five Colleges, and a trustee of Notre Dame University. She gained policy-making level experience in capital and financial markets through her service as a trustee of The Putnam Mutual Funds, where she has chaired the nominating committee and served on the brokerage, communications, contract, executive and investment oversight committees, and through her service as a director of publicly-traded companies including Bell Atlantic and NYNEX. Based on her qualifications and experience, the Board of Trustees determined that Dr. Kennan should serve as a Trustee.

Kenneth R. Leibler, Age: 63; Trustee since 2006. Mr. Leibler has served as a trustee of The Putnam Mutual Funds since 2006, a Trustee of Beth Israel Deaconess Medical Center since 2006, and Vice Chairman of the Board of Trustees of Beth Israel Deaconess Medical Center since 2009. He is a founding partner of the Boston Options Exchange and served as its Chairman from 2004 to February 2007. Mr. Leibler served as the Chairman and Chief Executive Officer of the Boston Stock Exchange from 2001 to 2005, and as President of Liberty Financial Companies from 1990 to 2000, where he also served as Chief Executive Officer from 1995 to 2000 and as Chief Operating Officer from 1990 to 1995. He also held various positions at the American Stock Exchange, including President and Chief Operating Officer as well as Chief Financial Officer from 1975 to 1990. He is a past Vice Chairman of the Board of Directors of ISO New England, Inc., the independent operator of New England s bulk electric transmission system, where he served until 2006. He also served as a director of The Ruder Finn Group from 2005 to 2010. Mr. Leibler received a B.A. magna cum laude from Syracuse University.

Mr. Leibler has considerable senior executive level experience in business and management, including experience in financial markets and risk assessment, as the former Chairman of the Boston Options Exchange, former Chairman and CEO of the Boston Stock Exchange, and former President, Chief Operating Officer and Chief Financial Officer of the American Stock Exchange, as well as through his current service as a trustee of The Putnam Mutual Funds, where he recently became chair of the Audit and Compliance Committee and serves on the pricing, distributions, investment oversight, and investment oversight coordinating committees. He also has policy-making level experience in the electric utility industry through his service as the Vice Chairman of ISO New England. Based on these qualifications, the Board of Trustees determined that Mr. Leibler should serve as a Trustee.

Robert E. Patricelli, Age: 72; Trustee since 1993. Mr. Patricelli has been Chairman and Chief Executive Officer of Women s Health USA, Inc., a provider of women s health care services, since 1997. Mr. Patricelli was Chairman and Chief Executive Officer of Evolution Benefits, Inc., a provider of employee benefit services, from 2000 to 2011. Mr. Patricelli previously served as Chairman, President and Chief Executive Officer of Value Health, Inc. from 1987 to 1997, and as Executive Vice President of CIGNA Corporation and President of CIGNA s Affiliated Businesses Group. Mr. Patricelli has also held various positions in the federal government, including White House Fellow, counsel to a United States Senate Subcommittee, Deputy Undersecretary of the Department of Health, Education and Welfare and Administrator of the United States Urban Mass Transportation Administration. Mr. Patricelli is a director of Interactive Health Solutions, Inc., Newman s Own Inc. and Newman s Own Foundation, and a former director of Prodigy Health Group. He is also a director of the MetroHartford Alliance, Inc., The Bushnell, the Ocean Exploration Trust, Inc. and the Connecticut Center for Science and Exploration. Mr. Patricelli received a B.A. from Wesleyan University and a J.D. from Harvard Law School, and was a Fulbright Scholar at the University of Paris.

Mr. Patricelli has significant policy-making level experience in businesses subject to governmental regulation as well as debt and equity finance as a result of his service as a director, lead director, chairman and chief executive officer of several public and private healthcare and biotechnology companies. He also has extensive political experience resulting from his service in the federal government, most recently as Deputy Undersecretary of the Department of Health, Education and Welfare and Administrator of the United States Urban Mass Transportation Administration. Based on these skills and experiences, the Board of Trustees determined that Mr. Patricelli should serve as a Trustee.

Charles W. Shivery, Age: 66; Trustee since 2004. Mr. Shivery has been Chairman of the Board, President and Chief Executive Officer of Northeast Utilities since March 29, 2004 and Chairman and a director of The Connecticut Light and Power Company, Public Service Company of New Hampshire, Western Massachusetts Electric Company and Yankee Gas Services Company since January 19, 2007. Mr. Shivery assumed his current position at Northeast Utilities after serving as interim President beginning in January 2004. From June 2002 until December 2003, Mr. Shivery served as President-Competitive Group of Northeast Utilities, as President and Chief Executive Officer and a director of NU Enterprises, Inc., and as Chairman and a director of most of Northeast Utilities competitive subsidiaries. In 2002, Mr. Shivery retired from Constellation Energy Group, Inc. (Constellation), parent company of Baltimore Gas and Electric Company (BG&E) and other energy-related businesses, having held numerous senior management positions at Constellation. Mr. Shivery is a director of Webster Financial Corporation, Energy Insurance Mutual, the Connecticut Business & Industry Association, Association of Edison Illuminating Companies, Connecticut Science Center, The Bushnell, Edison Electric Institute, and the Electric Power Research Institute. He is the Chairman of the MetroHartford Alliance, Inc. and the Connecticut Children s Medical Center. Mr. Shivery received B.A. and B.S. degrees from The Johns Hopkins University and an M.B.A. from the University of Baltimore.

Mr. Shivery has nearly 40 years of experience in the heavily regulated utility industry including policy-making level director and executive officer positions while employed at Constellation Energy and Northeast Utilities. He gained important senior management level experience in capital and financial markets, and credit markets, throughout his career at Constellation and Northeast Utilities. He has extensive experience interacting with elected and appointed officials in federal and state government and regulatory agencies. Based on his extensive experience and qualifications, the Board of Trustees determined that Mr. Shivery should serve as a Trustee.

John F. Swope, Age: 73; Trustee since 1992. During 1999 and 2000, Mr. Swope served as President and Chief Executive Officer of Public Broadcasting Service. Mr. Swope, a retired attorney, served as of counsel to the law firm of Sheehan Phinney Bass + Green PA from 1995 to 1997, and as President of Chubb Life Insurance Company of America from 1980 to 1994, after serving in various executive capacities at Chubb Life and its predecessor companies since the early 1970 s. Mr. Swope is a director of New Hampshire Public Television and New Hampshire Public Radio, a trustee of The Currier Museum of Art, and a member of the Corporation at the Woods Hole Oceanographic Institution. Mr. Swope received a Bachelor s Degree from Amherst College and a J.D. from Yale Law School.

Mr. Swope has significant experience as a senior executive officer in businesses heavily regulated by the federal government through his service as President and CEO of PBS, President of Chubb Life Insurance Company, and a director of New Hampshire Public Television and Radio. Based on his qualifications and experience, coupled with his law practice in a New Hampshire firm and other ties to the State of New Hampshire, the Board of Trustees determined that Mr. Swope should serve as a Trustee.

Dennis R. Wraase, Age: 67; Trustee since 2010. Mr. Wraase served as Chairman of the Board, Chief Executive Officer and a director of Pepco Holdings, Inc. (PHI) until his retirement in June 2009. He was elected Chairman of PHI in 2004, became Chief Executive Officer in 2003 and served as a director since 1998. He previously served as the President of PHI from 2001 to 2008, and Chief Operating Officer from 2002 to 2003. Mr. Wraase joined the Potomac Electric Power Company, a utility subsidiary of PHI (Pepco), in 1974, and held various positions of increasing leadership and responsibility, including President from 2000 to 2003 and Chief Financial Officer from 1996 to 2000. He joined Pepco s board of directors in 1998 and served as its Chairman and Chief Executive Officer from 2004 to 2009. Mr. Wraase received a B.S. in Accounting from the University of Maryland and an M.S. in Business Financial Management from The George Washington University. He is a certified public accountant. He is a member of the Financial Executives Institute and the American Institute of Certified Public Accountants. Mr. Wraase currently serves as the Executive-In-Residence at the Center for Social Value Creation at the Robert H. Smith School of Business, University of Maryland. He is also currently a director and Vice Chairman of the University of Maryland System Foundation and a director and Chairman of the Washington Hospital Center. Mr. Wraase previously served as a director of the Edison Electric Institute, The Association of Edison Illuminating Companies and the Institute for Electric Efficiency, and as President of the Southeastern Electric Exchange.

Mr. Wraase brings to Northeast Utilities considerable utility industry knowledge and experience gained through his career of service at Pepco. He has significant policy-making level experience in the heavily regulated industry as well as in the capital and financial markets, credit markets, financial reporting and accounting, and risk assessment. He has served on the board of directors of numerous companies, and he is a certified public accountant. Based on his extensive experience and qualifications, the Board of Trustees determined that Mr. Wraase should serve as a Trustee.

CL&P

Each member of CL&P s Board of Directors is an employee of CL&P, NU or an affiliate. Directors are elected annually to serve for one year until their successors are elected and qualified. The following sets forth the members of CL&P s Board of Directors and their current positions:

Name	Age	Title
Gregory B. Butler	54	Senior Vice President and General Counsel of NU and the Regulated companies
Jean M. LaVecchia	60	Vice President - Human Resources of NUSCO
David R. McHale	51	Executive Vice President and Chief Financial Officer of NU and the Regulated companies
Leon J. Olivier	63	Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of the Regulated companies
James B. Robb	51	Senior Vice President, Enterprise Planning and Development of NUSCO
Charles W. Shivery	66	Chairman of the Board, President and Chief Executive Officer of NU; Chairman of the Regulated companies

NU and CL&P

The following sets forth certain information as of February 15, 2012 concerning CL&P s Directors and NU s and CL&P s executive officers:

Name	Age	Title
Charles W. Shivery	66	Chairman of the Board, President and Chief Executive Officer of NU; Chairman of the Regulated companies
Leon J. Olivier	63	Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of the Regulated companies
David R. McHale	51	Executive Vice President and Chief Financial Officer of NU and the Regulated companies
Gregory B. Butler	54	Senior Vice President and General Counsel of NU and the Regulated companies
Jean M. LaVecchia**	60	Vice President - Human Resources of NUSCO

James B. Robb**	51	Senior Vice President, Enterprise Planning and Development of NUSCO
Jay S. Buth	42	Vice President - Accounting and Controller of NU and the Regulated companies
James A. Muntz*	54	President Transmission of NUSCO; President and Chief Operating Officer of CL&P

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Mr. Muntz was named President and Chief Operating Officer of CL&P on November 17, 2011 and is therefore solely an executive officer of CL&P.

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

Charles W. Shivery. Mr. Shivery has been Chairman of the Board, President and Chief Executive Officer of NU since March 29, 2004 and Chairman and a director of CL&P, PSNH, WMECO, and Yankee Gas since January 19, 2007. Mr. Shivery assumed his current position at NU after serving as interim President beginning in January 2004. From June 2002 until December 2003, Mr. Shivery served as President-Competitive Group of NU, as President and Chief Executive Officer and a director of NU Enterprises, Inc., and as Chairman and a director of most of NU s competitive subsidiaries. In 2002, Mr. Shivery retired from Constellation Energy Group, Inc. (Constellation), parent company of Baltimore Gas and Electric Company (BG&E) and other energy-related businesses, having held numerous senior management positions at Constellation. Mr. Shivery is a director of Webster Financial Corporation, Energy Insurance Mutual, the Connecticut Business & Industry Association, Association of Edison Illuminating Companies, Connecticut Science Center, The Bushnell, Edison Electric Institute, and the Electric Power Research Institute. He is the Chairman of the MetroHartford Alliance, Inc. and the Connecticut Children s Medical Center. Mr. Shivery received B.A. and B.S. degrees from The Johns Hopkins University and an M.B.A. from the University of Baltimore.

Leon J. Olivier. Mr. Olivier was elected Executive Vice President and Chief Operating Officer of NU effective May 13, 2008. Mr. Olivier 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.

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, he was 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.

Gregory B. Butler. Mr. Butler was elected Senior Vice President and General Counsel of NU effective December 1, 2005, and of CL&P, PSNH and WMECO, effective March 9, 2006, and was elected a Director of CL&P, PSNH and WMECO on 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.

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 on April 22, 2009 and a Director of Northeast Utilities Foundation, Inc. effective January 30, 2007.

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.

Jay S. Buth. Mr. Buth was elected 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.

James A. Muntz. Mr. Muntz has served as President Transmission of NUSCO since November 1, 2008, and Senior Vice President Transmission of CL&P, PSNH and WMECO since June 19, 2007. Mr. Muntz was also appointed to serve as President and Chief Operating Officer of CL&P on November 18, 2011 upon the resignation of Jeffrey D. Butler. Previously, Mr. Muntz served as Senior Vice President Transmission of NUSCO from June 19, 2007 to October 31, 2008 and Vice President Transmission Products of CL&P, PSNH and WMECO from January 17, 2005 to June 19, 2007. Mr. Muntz has also served as President of NPT since April 21, 2010.

There are no family relationships between any Trustee, Director or executive officer of NU or CL&P and any other Trustee, Director or executive officer of NU or CL&P, and none of the above Trustees, Directors or executive officers serves as a Trustee, Director or executive officer pursuant to any agreement or understanding with any other person.

Our executive officers hold office 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.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934 requires the Trustees and executive officers of NU, and persons who beneficially own more than ten percent of our outstanding common shares to file reports of ownership and changes in ownership with the SEC and the New York Stock Exchange. As a practical matter, we assist our Trustees and executive officers by monitoring transactions and completing and filing Section 16 reports on their behalf. Based on such reports and the written representations of our Trustees and executive officers, we believe that for the year ended December 31, 2011, all such reporting requirements were complied with in a timely manner.

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 the Standards of Business Conduct, which are 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

AUDIT COMMITTEE

NU has a separately-designated standing audit committee of its Board of Trustees established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934.

The Audit Committee consists of Richard H. Booth (Chair), Dennis R. Wraase (Vice Chair), John G. Graham, Elizabeth T. Kennan and Kenneth R. Leibler. Each member of the Audit Committee meets the independence requirements of the New York Stock Exchange and the SEC and under NU s Corporate Governance Guidelines. Each member of the Audit Committee meets the financial literacy requirements of the New York Stock Exchange and SEC. The Board of Trustees has affirmatively determined that Messrs. Booth, Graham and Leibler are audit committee financial experts, as that term is defined by the SEC.

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 s audit committee and audit committee experts.

Item 11.

Executive Compensation

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.

NU and CL&P

The information in this Item 11 relates solely to CL&P and NU.

COMPENSATION DISCUSSION AND ANALYSIS

The following disclosure is for NU and CL&P. In this disclosure, the term CEO refers to Charles W. Shivery, the Chairman, President and Chief Executive Officer of NU and Chairman of CL&P, PSNH and WMECO. Mr. Olivier, Executive Vice President and Chief Operating Officer of NU, also serves as the Chief Executive Officer of CL&P, PSNH and WMECO. In addition, the sections below contain disclosures concerning James A. Muntz, President Transmission of NUSCO, who was appointed to serve as President and Chief Operating Officer of CL&P on November 18, 2011 in the wake of the restoration efforts after the October 29, 2011 snowstorm until a permanent successor is elected. For purposes of this Item 11, Mr. Muntz is an executive officer of CL&P only.

EXECUTIVE SUMMARY

Pay for Performance Philosophy

Our Compensation Committee follows a philosophy of linking our named executive officers compensation to performance that will ultimately benefit customers and shareholders. We use compensation programs to attract and retain the best executive talent and to motivate our executives to exceed specific financial and organizational goals set each year. We strive to provide executives with base salary, performance-based annual incentive compensation and long-term incentive compensation opportunities that are competitive with the market. 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, maintaining a strong balance sheet, system reliability and customer service.

The Compensation Committee makes annual compensation decisions in a thoughtful and deliberate way using data that our independent compensation consultant provides and through open discussion within the Committee. The Compensation Committee periodically assesses the risks of our compensation programs and mitigates risks by:

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Rigorous analysis of goal setting in our incentive programs;

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Continuous monitoring of performance and risk;

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Imposing minimum performance thresholds and ceilings on incentive awards; and

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Providing discretion with respect to actual payouts.

In addition, our executives:

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Must comply with share ownership guidelines to more closely link their interests to those of shareholders;

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Are subject to clawback of incentive compensation under certain circumstances; and

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Are provided very few perquisites, all related primarily to business needs.

Alignment of Performance and Compensation

Our compensation philosophy, programs and practices support executive officers and employees as they work to meet and exceed both customer and shareholder expectations. The specific compensation programs that were in place during 2011 were approved during the first quarter of the year and were designed to retain key, talented executives during the continuing uncertainty in the capital markets and weakened economic conditions and incentivize them to create long-term value for customers and shareholders.

Pending Merger with NSTAR

During 2011, our shareholders approved the merger agreement for our pending merger with NSTAR and simultaneously approved an increase in the number of our common shares authorized for issuance. We also received approvals from a number of state and federal regulatory agencies and authorities. We have entered into settlement agreements with the Massachusetts Attorney General and the DOER agreeing to certain conditions with respect to the merger, which agreements are subject to approval by the DPU on April 4, 2012. We are also awaiting approval of the merger from PURA. After the closing of the transaction, the Company will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire.

The Compensation Committee faced unique challenges in 2011 related to executive retention and linking compensation of the executives to the interests of our shareholders as the transaction, first announced in October 2010, was pending during the entire year. The Committee acknowledged the critical importance of keeping the management team intact while the merger remained subject to closing conditions and regulatory approvals. In 2010, the Committee had approved a retention pool to be allocated to key employees to help ensure their continued dedication to the Company, both before and after completion of the merger, and to maintain a strong link between compensation and shareholder interests. In 2011, the Committee recommended, and the Board approved, a special grant of 76,406 restricted share units to Mr. Shivery, NU s Chairman, President and Chief Executive Officer, to recognize the critical role he has had and will play in the successful leadership of the Company through the close of the pending merger and as nonexecutive Chairman of the Board during the post-merger integration period.

During 2011, Mr. Shivery and the management team effectively pursued the federal and state regulatory approvals required to close the merger with NSTAR. At the end of 2011, only the approval of the DPU remained outstanding. However, in January 2012, the PURA revised its earlier decision concluding that it did not have jurisdiction to review the merger and determined that NU and NSTAR must obtain approval from the PURA prior to completing the merger. As a result, approvals from the DPU and PURA are currently outstanding. Mr. Shivery worked closely with NSTAR s Chief Executive Officer, Thomas J. May, to provide guidance and oversight to the merger integration plan to ensure that the Company is positioned to function effectively immediately after the closing. Members of management from both companies continue to work together closely in merger integration teams tasked with identifying the best practices to be implemented by the Company after the closing.

Storm Responses in 2011

On August 28, 2011, Tropical Storm Irene caused extensive damage to the Company s electric distribution system. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut. On October 29, 2011, an unprecedented snowstorm inundated our service territory with heavy snow, causing significant damage to our distribution and transmission systems. Approximately 1.2 million electric distribution customers were without power at the peak of the outages. The snowstorm was extraordinary, and we set very high performance expectations, a number of which we did not meet. As a result, in November 2011, CL&P established a storm fund reserve of $30 million to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011, as a result of the October snowstorm, and to provide contributions to certain Connecticut charitable organizations. CL&P also announced changes in senior leadership, appointing officers to lead emergency preparedness as well as infrastructure hardening to make the electric system more resistant to increasingly severe weather related events. As a result, certain members of senior management, including NU s Named Executive Officers, proposed to the Compensation Committee that they not receive an award under the 2011 Annual Incentive Award, and the Compensation Committee accepted that proposal.

State regulatory agencies in Connecticut, Massachusetts and New Hampshire opened inquiries into the responses of utilities in their states during the October snowstorm, including responses of CL&P, PSNH and WMECO. In addition, in Connecticut, the review included the responses of utilities during Tropical Storm Irene, and a consultant was engaged to conduct an audit into the emergency response programs of CL&P. These inquiries are expected to be completed in the second quarter of 2012. For further information regarding these inquiries, see *Regulatory Developments and Rate Matters 2011 Major Storms,* in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operation.

2011 Financial Performance

In 2011, the Company achieved:

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2011 earnings of $423.9 million, or $2.38 per share (excluding a charge of $17.9 million, or $0.10 per share, associated with the $30 million storm fund reserve and an after-tax charge of $11.3 million, or $0.06 per share, associated with the merger with NSTAR), compared with 2010 earnings of $387.9 million, or $2.19 per share;

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2011 Adjusted Net Income (ANI) of $406.0 million (excluding an after-tax charge of $11.3 million, or $0.06 per share, associated with the merger with NSTAR), compared with 2010 ANI of $400.6 million;

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Share price appreciation of 13.1 percent from a closing price of $31.88 on December 31, 2010 to a closing price of $36.07 on December 30, 2011, the last trading day of the year; and

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Total shareholder returns of 16.4 percent for the year ended December 31, 2011 and 67.4 percent for the three years ended December 31, 2011.

In 2011, the execution of the Company s long-term strategic plan as well as the annual operating and capital plans exceeded expectations. In addition, although approvals from the DPU and PURA remain outstanding, only the approval of the DPU remained outstanding at the end of 2011. The Company has also made significant progress toward integrating the companies after the closing.

For compensation purposes, NU s Named Executive Officers proposed that they not receive awards under the 2011 Annual Incentive Program and, while recognizing the many notable accomplishments in achieving or exceeding other strategic and operational goals by the NU leadership, the Compensation Committee accepted that proposal. As a result, notwithstanding strong financial performance and successful execution of the strategic operating plan and annual operating and capital plans in 2011, Mr. Shivery and NU s Named Executive Officers did not receive awards under the annual incentive program.

CEO Compensation

Mr. Shivery received total direct compensation of $9,685,241 for 2011, including the special equity grant of 76,406 restricted share units described above, valued at $2,574,118. Excluding the value of the special equity grant, Mr. Shivery received compensation of $7,111,123 for 2011, as compared with $8,254,374 for 2010.

OVERALL OBJECTIVES OF EXECUTIVE COMPENSATION PROGRAM

General

The fundamental objective of our Executive Compensation Program is to motivate executives and key employees to support our strategy of investing in and operating businesses that benefit customers, employees, and shareholders. As a holding company for several regulated utilities, 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.

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

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Attract and retain key executives by providing total compensation competitive with that of other executives employed by companies of similar size and complexity in the utility and general industries. The program relies on compensation data obtained from consultants surveys of companies and from a customized peer group to ensure that compensation opportunities are competitive and capable of attracting and retaining executives with the experience and talent required to achieve our strategic objectives. As we continue to grow and improve our 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 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 our business strategies. This linkage to critical goals helps to align executives with our 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.

NU provides its shareholders with the opportunity to cast an annual advisory vote on executive compensation (a say-on-pay proposal). At NU s annual meeting of shareholders held in May 2011, over 97 percent of the votes cast on the say-on-pay proposal were voted to approve the compensation of NU s Named Executive Officers, as described in our 2011 proxy statement. The Compensation Committee believes this affirms shareholders support of the executive compensation program, and the Committee did not make any changes to the executive compensation program in 2011 as a result of the say-on-pay vote. The Compensation Committee will continue to consider the outcome of the Company s say-on-pay votes when making future compensation decisions for the Named Executive Officers.

NAMED EXECUTIVE OFFICERS

The executive officers listed in the Summary Compensation Table in this Item 11 whose compensation is discussed in this CD&A are referred to as the Named Executive Officers or NEOs. The Summary Compensation table includes the NEOs for both NU and CL&P. For 2011, the Named Executive Officers for both NU and CL&P are:

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Charles W. Shivery, Chairman of the Board, President and Chief Executive Officer of NU and Chairman of the Regulated companies

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David R. McHale, Executive Vice President and Chief Financial Officer of NU and the Regulated companies

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Leon J. Olivier, Executive Vice President and Chief Operating Officer of NU and Chief Executive Officer of the Regulated companies

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Gregory B. Butler, Senior Vice President and General Counsel of NU and the Regulated companies

In addition, James B. Robb, Senior Vice President-Enterprise Planning and Development of NUSCO, is a Named Executive Officer for NU only, and James A. Muntz, President Transmission of NUSCO, who was appointed to serve as President and Chief Operating Officer of CL&P on November 18, 2011, in the wake of the storm restoration following the October 2011 snowstorm until a permanent successor is named, is a Named Executive Officer for CL&P only.

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 our business. The design and implementation of the overall compensation program provides the Compensation Committee with opportunities throughout the year to assess risks within the compensation program that may have a material effect on the Company and our shareholders.

Each year, as part of its annual planning process, the 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 assessed the risks associated with the executive compensation program 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. Key elements of the executive compensation program have not changed since the review in 2009.

The Compensation Committee periodically assesses the risks of our compensation programs and mitigates risks by continuous monitoring of performance and risk.

ELEMENTS OF 2011 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 business unit or function
Long-Term Incentive Program	Variable compensation consisting of 75% Performance shares and 25% RSUs (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
· Performance shares	Long-term incentive, consisting solely of performance shares, that rewards individuals for corporate performance over a three-year period based on achieving pre-established levels of:	Reward performance on key corporate priorities that are also key drivers of total shareholder return performance

	· Cumulative net income	Align executive and shareholder interests through share performance and share ownership
	· Average return on equity	Strengthen the link between long-term compensation and total shareholder return performance
	· Average credit rating	Encourage long-term thinking and commitment to the Company
	· Total shareholder return relative to a group of comparable utility companies	
Supplemental Benefits	Supplemental Executive Retirement Plan, Nonqualified Deferred Compensation, and Perquisites	Supplemental benefits intended to help 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 above only) Executives hired after 2005 are ineligible for these benefits	Compensate for Internal Revenue Code limits on qualified plans Aid in retention of executives and enhance long-term commitment to the Company

· Other Nonqualified Deferred Compensation (Deferral Plan)	Opportunity to defer base salary and annual incentives, using the same investment vehicles as NU s qualified 401(k) plan, and receive matching contributions otherwise capped by Internal Revenue Code limits on qualified plans Each year s matching contribution vests after three years or at retirement For executives hired after 2005, who are ineligible to participate in our defined benefit pension plan, we make 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
· Med-Vantage Plan	For executives hired after 2005, who are ineligible to participate in our defined benefit pension plan, starting at age 40 we make contributions of $1,000 per year to a qualified retiree medical savings account	Designed to help build tax-free savings for post-employment health care expenses
· Perquisites	Tax preparation and financial planning reimbursement benefit (certain senior executives) Executive physical examination reimbursement plan Reimbursement of relocation expenses for newly hired and transferred executives	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

	Reimbursement of spousal travel expenses only for business purposes	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 and Mr. Muntz participate in a Special Severance Program (SSP) 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 target mix of compensation for our CEO and the other executive officers 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 the compensation for each executive officer based on the relative authority, duties and responsibilities of each office. Our CEO s responsibilities for the daily operations and management of the Northeast Utilities System companies are significantly greater than the duties and responsibilities of our other executive officers. As a result, our CEO s compensation is significantly higher than the compensation of our other executive officers. We regularly review market compensation data for executive officer positions similar to those held by our executive officers, including our CEO, and this market data continues to indicate that chief executive officers are typically paid significantly more than other executive officers. For 2011, target annual incentive and long-term incentive compensation opportunities for our CEO 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 2011 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
Charles W. Shivery	20%	20%	45%	15%(4)	100%
David R. McHale	32%	20%	36%	12%	100%
Leon J. Olivier	32%	20%	36%	12%	100%
Gregory B. Butler	32%	20%	36%	12%	100%
James B. Robb	40%	20%	30%	10%	100%
James A. Muntz	40%	20%	30%	10%	100%
NEO average, excluding CEO	34%	20%	34.5%	11.5%	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.

(4)

Excludes 76,406 RSUs granted to Mr. Shivery in 2011 to recognize the critical role he has had and will play in the successful leadership of the Company through the close of the proposed merger with NSTAR and as nonexecutive Chairman of the Board during the post-merger integration period.

MARKET ANALYSIS

The Compensation Committee strives to provide our executive officers with target compensation opportunities over time at or above the median compensation levels for executive officers of companies comparable to us. The Committee determined executive officer TDC levels in two steps. First, the Committee determined the market values of executive officer compensation elements (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 2011 compensation:

·

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 size-adjusted utility and general industry survey data to determine base salaries and incentive opportunities. Then the Committee compared utility-specific executive officer positions, including our Executive Vice President and Chief Operating Officer, to utility-specific market values. For executive officer positions that have counterparts in general industry, including our 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, as both groups represent the talent market for these executive officers.

·

Customized peer group data. The Committee also evaluated compensation data obtained from reviews of proxy statements from our customized group of peer utility c4ompanies. 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 reviewed the composition of our customized peer group in 2011 and compared the group against our size guidelines of revenues between approximately $3 billion and $12 billion. Notwithstanding 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 peer group selected by the Committee in 2011 included two fewer utilities than the group used in 2010. One company was omitted because it had been acquired, while a second company was omitted because it fell outside the Committee s revenue guidelines. As a result, in support of executive pay decisions during 2011, our customized peer group consisted of utilities with annual revenues that ranged from $2.3 billion to $10.6 billion with median annual revenues of $4.6 billion. We 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 2011 included the CEO, Chief Operating Officer, Chief Financial Officer, and General Counsel. For 2011, the peer group consisted of the following 18 companies:

Allliant Energy Corporation	Integrys Energy Group Inc.	Pinnacle West Capital Corporation
Ameren Corporation	NiSource Inc.	Progress Energy, Inc
CenterPoint Corporation	NSTAR	SCANA Corporation
CMS Energy Corporation	NV Energy, Inc.	TECO Energy, Inc.
DTE Energy Company	OGE Energy Corp.	Wisconsin Energy Corporation
Great Plains Energy Incorporated	Pepco Holdings, Inc.	Xcel Energy, Inc.

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. Any adjustments are made gradually over time to avoid radical changes. The Committee used compensation data obtained from the companies listed above for insights into incentive compensation design practices and compensation levels, although no specific actions were taken in 2011 directly as a result of this information. In 2011, the Committee also used this group for performance comparisons under the 2011 2013 Long-Term Incentive Program.

The Compensation Committee also (i) determines perquisites to the extent they serve business purposes and (ii) sets supplemental benefits at levels that provide market-based compensation opportunities to the executive officers. 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)

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Targeted market pay positioning for each executive officer

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Individual experience and years of service

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

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Internal equity

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

INCENTIVE COMPENSATION

The annual incentive program and the long-term incentive program are provided under the Northeast Utilities Incentive Plan, which was approved by our shareholders at the 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.

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.

2011 ANNUAL INCENTIVE PROGRAM

The 2011 Annual Incentive Program consisted of a corporate goal plus individual goals for each NEO. The Compensation Committee set the annual incentive compensation targets for 2011 at 100% of base salary for our CEO 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 we achieve 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 33 officers, including the NEOs, participated in the 2011 Annual Incentive Program.

2011 Corporate Goal

The objective of the 2011 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 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 2011, the Compensation Committee established the ANI target at $415.8 million. The ANI target reflects the midpoint of the range of internal ANI estimates calculated at the beginning of the year. The ANI thresholds for the individual and corporate goals appear below (dollars in millions):

Threshold For Individual Goals (20% below ANI Target)	Minimum Corporate Goal (10% below ANI Target)	2011 ANI Target	Maximum Corporate Goal (10% above ANI Target)	Actual 2011 ANI
$332.6	$374.2	$415.8	$457.4	$406.0

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 2011, the Committee also considered and agreed upon exclusions from ANI consisting of certain nonrecurring income and expense items or events that were either beyond the control of management generally or related to a decision by the Committee not to penalize executive officers for making correct strategic business decisions. The Compensation Committee approved all final exclusions from ANI. The income and expense items set forth below were excluded from ANI in 2011.

Excluded Categories	Specific 2011 Adjustments ($ in millions)
Incremental NSTAR merger costs	(11.3)
Net Adjustments:	**$(11.3)**

2011 Individual Goals

The 2011 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 the Corporate Governance Committee determines the CEO s proposed annual incentive program payment based on the extent to which individual and corporate goals have been achieved. The Compensation Committee recommends to the Board of Trustees for approval the proposed award for the CEO. For the remaining NEOs, the CEO 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 2011

The following table sets forth the weighting of the annual incentive program corporate goal and individual goals for each NEO for 2011. These weightings reflect the Compensation Committee s desire to balance individual accountability with teamwork across the organization. Individual goals for our NEOs 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	60%	40%	Complete the merger with NSTAR on terms that meet the objectives approved by the Board of Trustees and outlined in the merger documents (25% of individual goals).
Chairman of the Board, President, and Chief Executive Officer of NU; Chairman of the Regulated companies			Working with NSTAR CEO Thomas J. May, actively provide oversight to the integration planning process to ensure that the Company functions effectively after the closing. Special emphasis to be placed on the cultural changes necessary to generate the anticipated benefits of the merger (25% of individual goals).
			Operating as an independent company until the merger is completed, effectively execute the Company s approved 2011 operating and capital plan (20% of individual goals).
			Operating as an independent company until the merger is approved, continue to execute the key elements of the Company s 2011-2015 strategic plan (20% of individual goals).
			Until the merger is completed, continue to embed sustainability into the Company s operations and relationships with its key stakeholders. Continue to improve the Company s reputation among the various stakeholders. Take an active role in evolving energy policy nationally, regionally and in each our jurisdictional states (10% of individual goals).
David R. McHale	60%	40%	As lead integration officer for the merger with NSTAR, working with the integration project management team, lead the design and implementation of the merger integration effort (40% of individual goals).
Executive Vice President and Chief Financial Officer of NU and the Regulated companies			Achieve the 2011 financial plan to meet funding and liquidity requirements necessary to achieve the 2011

operating plan. Support on-going rate cases and develop and implement a regulatory strategy which meets the objectives of the 2011 operating plan. Develop strategic alignment between the shared services organization and operating businesses while effectively managing costs and efficient delivery of services (25% of individual goals).

Implement the 2011 Talent Management Program and develop a new organization to support the merger with NSTAR (15% of individual goals).

Continue to execute the Company's strategy that brings customer focus to the forefront of the organization (5% of individual goals).

Support and advance the Company s strategy and position the Company to successfully pursue new opportunities. Position the Company to finance current and future growth while ensuring the integrity of the Company's financial position (5% of individual goals).

Communicate the Company s strategy and financial position throughout the organization and with external stakeholders, with an emphasis on investors, shareholders, members of the financial community and employees with respect to the merger with NSTAR (5% of individual goals).

Manage the CFO and Shared Services budget and capital expenditures (5% of individual goals).

Leon J. Olivier Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of the Regulated companies	50%	50%	Achieve the Company s 2011 operating plans, with special emphasis on plan execution, process improvement and meeting the transmission and operating companies operational objectives (35% of individual goals). Advance the Company s strategic objectives with special emphasis on the NEEWS project, the Northern Pass project, a successful outcome in the Yankee Gas Rate Case and achieving integration goals in the merger with NSTAR (35% of individual goals). Meet major customer experience 2011 initiatives, including customer satisfaction improvement, meter data management, and 2011 customer experience metrics (10% of individual goals). Implement safety improvement initiatives in support of measurable improvements in overall safety results (10% of individual goals). Work with CEO and executive team to build stakeholder confidence; apply rigorous financial performance management across all companies (10% of individual goals).
Gregory B. Butler Senior Vice President and General Counsel of NU and the Regulated companies	50%	50%	Provide strategic counsel to the Board of Trustees, CEO, and management to review and assess future strategic opportunities (35% of individual goals). Support implementation of the Company s operating and capital plans (20% of individual goals). Develop legislative, regulatory, legal and communications plans to implement the Company s 2011-2015 strategic plan (20% of individual goals).

Contribute to the development of the Company s view on major energy and environmental policy issues as necessary to position the Company as a leading regional and national expert on energy issues (10% of individual goals).

Increase and make more effective engagement of employees in Legal and Governmental Affairs departments through talent management, succession planning, and individual career and professional development. Develop, manage and execute plan to effectively and efficiently integrate with the NSTAR legal department following the merger (5% of individual goals).

Provide leadership to ensure high quality customer support in the Legal and Governmental Affairs departments to help the company advance overall customer experience (5% of individual goals).

Successfully manage legal and corporate affairs areas within established budgets (5% of individual goals).

James B. Robb Senior Vice President Enterprise Planning and Development, Northeast Utilities Service Company (NEO for NU only)	50%	50%	Finalize Smart Grid Road Map recommendations. Continue to develop electric vehicle strategies. Support Distribution Asset Management strategy development process (15% of individual goals). Refocus research and development efforts across the Company (EPRI, UCONN, Utility Technology Challenge). Conduct successful research and development pilots (15% of individual goals). Continue to evolve the Company s understanding of the regional power market and emerging opportunities to drive profitable growth (15% of individual goals). Evolve the Company s policies statements and preferred outcomes around carbon, renewables, transmission rules, energy efficiency and market structure. Work with Governmental Affairs in crafting policy strategies (15% of individual goals). Continue to build the Company s reputation as a national and regional thought leader on energy sector issues (10% of individual goals). Keep Northern Pass project on track. Transition full implementation of leadership after receipt of FERC approval (10% of individual goals). Support operating subsidiaries and strategic projects as required (10% of individual goals). Engage employees in strategy issues and the Company s direction through live presentations, intranet and other

			communication outlets (5% of individual goals).
			Effectively integrate relevant planning and analytic functions of the Company and NSTAR (5% of individual goals).
James A. Muntz	50%	50%	Execute the 2011 operating plan including key initiatives (25% of individual goals).
President -Transmission, NUSCO; appointed to serve as President and Chief Operating Officer, CL&P on November 18, 2011 (NEO for CL&P only)			Achieve NEEWS project goals, Northern Pass Transmission Project goals, Transmission's business development goals and Transmission's NSTAR merger integration goals (45% of individual goals).
			Leadership role in shaping regional and national transmission and energy policy (10% of individual goals).
			Achieve 2011 Transmission net income target (20% of individual goals).

2011 Results

The 2011 actual ANI was $406.0 million. However, as discussed in the Executive Summary, above, NU s Named Executive Officers proposed to the Committee that they not receive awards under the 2011 Annual Incentive Program, and the Committee accepted that proposal.

CEO Evaluation

The Compensation Committee and the Corporate Governance Committee assessed Mr. Shivery s performance during 2011. The Committee determined that Mr. Shivery's execution of our long-term strategic plan as well as our 2011 operating and capital plans exceeded expectations. The Company delivered improved financial performance with strong control over costs and sound operations.

During 2011, Mr. Shivery and the management team aggressively pursued the federal and state regulatory approvals required to close the pending merger with NSTAR. Through his leadership and direction, only the approval of the DPU remained outstanding at the end of 2011. Currently, approvals from the DPU and PURA remain outstanding and efforts continue to obtain them. Mr. Shivery

worked closely with NSTAR s Chief Executive Officer, Thomas J. May, to provide guidance and oversight to the merger integration process to ensure that the Company is positioned to function effectively immediately after the closing.

As described above, notwithstanding strong financial performance, successful execution of the strategic operating plan and annual operating and capital plans, and significant accomplishments in connection with the pending merger with NSTAR during 2011, for compensation purposes, Mr. Shivery proposed to the Committee that he not receive an award under the annual incentive program, and the Committee accepted his proposal.

Evaluations of Other Named Executive Officers

The Compensation Committee also reviewed the individual performance of each of the other NEOs. These factors included the scope of each NEO s responsibilities, performance, and impact on or contribution to our corporate success and growth. None of the NEOs listed below received awards under the 2011 Annual Incentive Program, except for Mr. Muntz, President Transmission of NUSCO, who was appointed to serve as the President and Chief Operating Officer of CL&P effective November 18, 2011, and is a Named Executive Officer of CL&P only.

Name and Principal Position	Annual Incentive Payment	2011 Accomplishments
David R. McHale Executive Vice President and Chief Financial Officer of NU and the Regulated companies	$0	The Compensation Committee determined that Mr. McHale and his organization effectively managed the regulatory approval process for the pending merger with NSTAR. In addition, Mr. McHale demonstrated leadership and initiative in managing all aspects of the merger integration process. Mr. McHale and his team successfully executed the 2011 financing plan, issuing debt on favorable terms, and maintaining and enhancing liquidity through a period of continued economic contraction
Leon J. Olivier Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of the Regulated companies	$ 0	The Committee determined that Mr. Olivier and his team successfully executed the 2011 operating plans and the five-year strategic plan. Mr. Olivier s significant accomplishments in 2011 included the achievement of important objectives related to the NEEWS project and merger integration. Mr. Olivier also exceeded objectives for customer service performance measurements and effectively completed the 2011 capital program.
Gregory B. Butler Senior Vice President and General Counsel of NU and the Regulated companies	$ 0	The Compensation Committee determined that Mr. Butler provided comprehensive strategic counsel to the Board of Trustees, CEO, and management, including in connection with the pending merger with NSTAR. Mr. Butler and his organization effectively managed the regulatory approval process for the NSTAR merger. He and his

		team contributed significantly to supporting the Company s 2011 operational and strategic objectives, including the NEEWS project, and continued to position the Company as a leading regional and national expert on energy issues.
James B. Robb Senior Vice President Enterprise Planning and Development, NUSCO (NEO of NU only).	$ 0	The Compensation Committee determined that Mr. Robb and his team continued to enhance the Company s understanding of the regional power market and emerging opportunities, including in particular opportunities in solar power and natural gas. Mr. Robb and his team continued to evolve the Company s policies with respect to renewable energy, energy efficiency and carbon, and to enhance the Company s reputation as a national leader on energy issues.
James A. Muntz President -Transmission, NUSCO; President and Chief Operating Officer, CL&P (NEO of CL&P only).	$297,614	The Compensation Committee determined that Mr. Muntz and his team achieved significant milestones under the NEEWS projects during 2011. In addition, Mr. Muntz s team exceeded the Transmission business financial and operating goals, and continued to achieve industry-leading NERC compliance ratings. Mr. Muntz assumed leadership roles following Tropical Storm Irene and the October snowstorm, and was instrumental in leading CL&P s storm restoration efforts. Mr. Muntz was appointed to serve as President and Chief Operating Officer of CL&P effective November 18, 2011 until a permanent successor is elected.

LONG-TERM INCENTIVE PROGRAMS

General

Under our 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 our CEO as a percentage of base salary on the date of grant. This recommendation is presented to the Board of Trustees 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. For the 2011 2013 Long-Term Incentive Program, at target, each grant generally consisted of 75% performance shares and 25% RSUs, 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 our CEO s targets), reflecting the Committee s desire to balance the roles of total shareholder return and our corporate financial performance in our compensation programs.

For the 2011 2013 program, the Compensation Committee acting jointly with the Corporate Governance Committee recommended to the Board of Trustees a long-term incentive compensation target for our CEO 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 under the 2011 2013 program 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 our 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 5% 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 our CEO. Based on input from our CEO, the Compensation Committee determines the final RSU grants for each of the other officers, including the other NEOs.

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 2011 2013 Program

Under the 2011 2013 program, the target RSU grant totaled approximately $2,504,978 million for all 33 officers participating in the long-term incentive program. The Committee did not adjust any officer s RSU grant from target for the 2011 2013 program. Accordingly, the final total RSU grant for officers, including NU s CEO, was unchanged from target. Dividing the final total RSU grant by $32.72, the average closing price for NU common shares during the last ten trading days in January 2011, resulted in an aggregate of 76,558 RSUs. The following RSU grants at 100% of target were approved, reflected in RSUs: Mr. Shivery: 24,526; Mr. McHale: 6,197; Mr. Olivier: 6,524; Mr. Butler: 4,814; Mr. Robb: 3,148 and Mr. Muntz: 3,148.

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. The performance-based component of our long-term incentive programs has continued to evolve over the three prior years by shifting a portion of performance cash in earlier programs to performance shares in more recent programs to further strengthen the alignment of the performance elements with our shareholders.

Long-Term Incentive Program	Percentage of Performance Cash	Percentage of Performance Shares
2008 2010	100%	0%
2009 2011	67%	33%
2010 2012	50%	50%
2011 2013	0%	100%

The Committee approved the 2011 2013 program in early 2011. The performance unit grant in the 2011 2013 program consisted solely of a performance share grant. Under all of our long-term programs, 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.

Awards under a program are earned to the extent to which we achieve goals in the four metrics described below during the three years 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. The selection of these four metrics reflects the Compensation Committee s belief that these areas are critical measurements of corporate success.

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Cumulative Adjusted Net Income, which is consolidated Northeast Utilities net income adjusted by the Compensation Committee to exclude the effects of certain nonrecurring income and expense items or events (which we defined as ANI under the annual incentive program) over the three years in a program (20%).

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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 (20%).

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Average credit rating of Northeast Utilities (excluding the regulated utilities), which is the time-weighted average daily credit rating by the rating agencies Standard & Poor s, Moody s, and Fitch. The metric is calculated by assigning numerical values, 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 (20%).

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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 (40%).

Each metric was weighted equally in the 2009 2011 program. In the 2010 2012 program, the weighting of the total shareholder return metric was increased to 40% and the remaining three metrics were reduced to 20% each, to strengthen the alignment between executives and shareholders. The Committee measures performance against the cumulative adjusted net income, average adjusted ROE, and average credit rating, because these metrics are directly related to our 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, we must achieve a minimum level of performance under that metric. If we achieve the minimum level of performance for any goal, then the resulting payout will equal 50% of the target for that goal. If we achieve 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.

Upon closing of the proposed merger with NSTAR, the extent of satisfaction of the performance goals applicable to performance units for performance periods not yet completed in the 2010 2012 program generally will be measured based on performance up to the closing of the merger and payment generally will be made on a pro-rata basis (based on the portion of the applicable performance period that had been completed upon closing of the merger) following the end of the original performance period conditioned upon continued employment through such date. Performance units outstanding immediately before the closing of the merger that are attributable to the portion of the applicable performance periods extending beyond the closing of the merger will be forfeited. However, if an executive officer experiences a qualifying termination of employment (a termination of employment before age 65 by the Company without cause or by the executive officer for good reason) before completion of the original performance period, the awards will be vested at target performance levels and paid out without pro-ration upon such termination. Subject to the closing of the merger, the Committee intends to grant to each executive officer whose awards are paid on a pro-rated basis a make-whole award of RSUs with a

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value equal to the value of the executive officer s Performance Units outstanding at target immediately before the closing of the merger that are attributable to the portion of the applicable performance periods extending beyond the closing of the merger.

Upon the closing of the pending merger with NSTAR, all performance shares outstanding under the 2011 2013 program will be converted to RSUs assuming a target level of performance. These RSUs will vest according to the schedule that applies to the RSU component already granted as part of the 2011 2013 program.

Set forth below are descriptions of each of the three long-term performance programs that were in effect during 2011. 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 ours. The Committee compared our total shareholder return to the total shareholder returns of the companies in the performance peer group. 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.

2009 2011 Performance Units

The Compensation Committee approved the 2009 2011 performance unit grants in early 2009, consisting of two-thirds performance cash and one-third performance shares. Upon completion of our fiscal year ended 2011, the Committee determined that we 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 100% of target.

For the 2009 2011 program, cumulative adjusted net income and average adjusted ROE excluded the effects of the following nonrecurring expense item:

Excluded Categories	**Specific 2011 Adjustments ($ in millions)**
Incremental NSTAR merger costs	$(11.3)
Net Adjustments:	**$(11.3)**

The table set forth below describes the goals under the 2009 2011 program and our actual results during that period:

2009 2011 Program Goals

Goal (1)	Minimum	Target	Maximum	Actual Results
Cumulative Adjusted Net Income ($ in millions)	$899.3	$999.2	$1,099.1	$1,137.7
Average Adjusted ROE	8.4%	9.3%	10.1%	10.3%
Average Credit Rating Points	1.2	1.7	2.2	1.7
Relative Total Shareholder Return (percentile) (2)	40th	60th	80th	32nd

(1)

Goals were evenly weighted in the 2009 2011 program.

(2)

The performance peer group for the 2009 2011 program included 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.

Based on our financial performance during the three-year performance period, the total payout under the 2009 2011 Long-Term Incentive Program equaled 100% of target. As a result, the Committee approved the following performance cash awards: Mr. Shivery: $1,552,500; Mr. McHale: $393,750; Mr. Olivier: $412,500; Mr. Butler: $305,241; Mr. Robb: $200,000; and Mr. Muntz: $200,000. In addition, the Committee approved the following performance share awards: Mr. Shivery: 32,702 shares; Mr. McHale: 8,294 shares; Mr. Olivier: 8,689 shares; Mr. Butler: 6,430 shares; Mr. Robb: 4,213 shares; and Mr. Muntz: 4,213 shares. These awards were determined pursuant to formulas set forth in the 2009 2011 Long-Term Incentive Program and were not subject to the discretion of the Compensation Committee.

2010 2012 Performance Units

The Committee approved the 2010 2012 performance unit goals in early 2010. No awards have been paid under this program, and the Committee will not determine whether any awards are payable until the earlier of the end of our 2012 fiscal year, which is the final year in the three-year program, or upon the closing of the pending merger with NSTAR, as described above.

As described above, under the 2010 2012 program, one-half of each performance unit grant consists of a performance cash grant and the remaining one-half of each performance unit grant consists of a performance share grant. The 2010 2012 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 2010 2012 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 our business; the acquisition of shares or assets of another entity comprising an additional segment or component of our business; and impairments on goodwill acquired before 2003 (more than seven years prior to the beginning of this program cycle).

The table set forth below describes the goals under the 2010 2012 program:

	2010 2012 Program Goals		
Goal (1)	**Minimum**	**Target**	**Maximum**
Cumulative Adjusted Net Income ($ in millions)	$1,051.6	$1,168.4	$1,285.2
Average Adjusted ROE	9.0%	9.9%	10.7%
Average Credit Rating Points	1.2	1.7	2.2
Relative Total Shareholder Return (percentile) (2)	40th	60th	80th

(1)

Relative total shareholder return accounted for 40% of the performance units granted in the 2010 2012 program while the cumulative adjusted net income, average adjusted ROE, and average credit rating metrics each accounted for 20% of the performance units granted.

(2)

The performance peer group for the 2010 2012 program includes Northeast Utilities and the following companies: 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.

2011 2013 Performance Shares

The Committee approved the 2011 2013 performance share goals in early 2013. No awards have been paid under this program, and the Committee will not determine whether any awards are payable until the end of our 2013 fiscal year, which is the final year in the three-year program.

As described above, under the 2011 2013 program, each performance grant consists solely of a performance share grant. The 2011 2013 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 2011 2013 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 our business; the acquisition of shares or assets of another entity comprising an additional segment or component of our business; and impairments on goodwill acquired before 2003 (more than eight years prior to the beginning of this program cycle).

The table set forth below describes the goals under the 2011 2013 program:

	2011 2013 Program Goals		
Goal (1)	**Minimum**	**Target**	**Maximum**
Cumulative Adjusted Net Income ($ in millions)	$1,187.5	$1,319.4	$1,451.3
Average Adjusted ROE	9.5%	10.4%	11.3%
Average Credit Rating Points	1.2	1.7	2.2
Relative Total Shareholder Return (percentile) (2)	40th	60th	80th

(1)

Relative total shareholder return accounted for 40% of the performance units granted in the 2011 2013 program while the cumulative adjusted net income, average adjusted ROE, and average credit rating metrics each accounted for 20% of the performance shares granted.

(2)

The performance peer group for the 2011 2013 program includes Northeast Utilities and the following companies: Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., CMS Energy Corporation, 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.

SPECIAL EQUITY GRANT

On February 8, 2011, the Board of Trustees approved a special grant of 76,406 RSUs to Mr. Shivery to recognize the critical role he has had and will play in the successful leadership of the Company through the close of the proposed merger with NSTAR and as nonexecutive Chairman of the Board during the post-merger integration period. The RSUs will vest eighteen months after the closing of the merger with NSTAR, coinciding with Mr. Shivery s commitment to remain as nonexecutive Chairman of the Board through that date. If Mr. Shivery dies or becomes disabled prior to the vesting date, then the RSUs will vest as of the date of death or disability. If Mr. Shivery does not serve on the Board through eighteen months after the merger closes, or the merger does not close, then the RSUs will be forfeited.

2012 CHANGES

2012 Incentive Programs

In early 2012, the Compensation Committee approved the 2012 Annual Incentive Program and the 2012 2014 Long-Term Incentive Program. At the time that the Committee established the performance goals for 2012, 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. For 2012, the Committee acknowledged that increased amounts will be invested to further strengthen the system s emergency preparedness and abilities to respond to storms. The Committee also acknowledged that enhanced emergency preparedness and system hardening programs were being evaluated as a result of the 2011 storms. Accordingly, the Committee agreed to consider excluding from ANI, in its discretion, expenses resulting from the implementation of emergency preparedness initiatives and system hardening programs. The Committee determined to encourage management to implement these initiatives and programs, if appropriate, which the Committee believes will benefit customers by enhancing the reliability and storm resistance of the electric system. Similar to the 2011 2013 Long-Term Incentive Program, upon the closing of the pending merger with NSTAR, all outstanding 2012 2014 performance shares will be converted to RSUs assuming a target level of performance. These RSUs will vest according to the schedule that applies to the RSU component already granted as part of the 2012 2014 Long-Term Incentive Program.

CLAWBACKS

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 CEO 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 the 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 clawback provisions or the Incentive Plan clawback provisions would apply.

SHARE OWNERSHIP GUIDELINES

Effective in 2006, the Compensation Committee approved share ownership guidelines to emphasize the importance of share ownership by certain of our executive officers. The Committee most recently reviewed the guidelines for these executive officers in 2010 and determined that they remain reasonable and require no modification. The guidelines call for the CEO to own 200,000 common 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
CEO	200,000	5-6
EVPs / SVPs	30,000 45,000	2-3
VPs	3,000 17,500	1-2

At the time the share ownership guidelines were implemented, the Committee required our executive officers to attain these ownership levels within five years. The Committee requires all newly-elected executive officers to attain the ownership levels within five to seven years. All of our executive officers, including our NEOs, have satisfied the share ownership guidelines, or are expected to satisfy them within the applicable timeframe. Common shares, whether held of record, in street name, or in individual 401(k) accounts, and RSUs satisfy the guidelines. Unexercised stock options and unvested performance shares do not count toward the ownership guidelines.

SUPPLEMENTAL BENEFITS

We provide a variety of basic and supplemental benefits designed to assist us in attracting and retaining executive officers critical to our 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 us or our 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 service. 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.

We 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 pension based on a prescribed formula if he meets certain eligibility requirements. See the Pension Benefits Table and the accompanying narrative for more details of this arrangement.

We entered into an employment agreement with Mr. Muntz that includes, depending on his age at termination of employment, a special annual or lump sum retirement benefit calculated using certain service credits and offset amounts. 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 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.

MED-VANTAGE PLAN

We automatically enroll K-Vantage employees who have attained at least age 40 in the Med-Vantage Plan to help pay for medical expenses, including healthcare premiums on a tax-favored basis upon the employee's termination of employment. Eligible full-time employees receive employer contributions of $1,000 per year.

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. We match 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 our common shares. We also credit 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.

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.

We do not 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

We have entered into employment and other agreements with certain executive officers, including Messrs. Shivery, McHale, Olivier, Butler, Robb and Muntz. 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 customary 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.

The agreements with Messrs. McHale, Butler and Robb provide for enhanced cash severance benefits in the event of a change of control and subsequent 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 our 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 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. The change of control provisions in Mr. Shivery s employment agreement expired when Mr. Shivery reached age 65. The employment agreements of Mr. Olivier and Mr. Muntz do not provide for severance payments in the event of termination of employment following a change of control. Mr. Olivier and Mr. Muntz participate instead in the Special Severance Program.

For Messrs. 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 the 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 Messrs. Olivier, Robb and Muntz will be reimbursed for the full amount of any excise taxes imposed on severance payments and any other payments under Section 4999 of the Internal Revenue Code. This gross-up is intended to preserve the aggregate amount of the severance payments by compensating the executive officers for any adverse tax consequences to which they may become subject under the Internal Revenue Code. We have not included gross-up provisions in any employment arrangements entered into with executive officers hired beginning with Mr. Robb. The severance payments for Messrs. Olivier, Robb and Muntz 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 notes appearing in this Item 11 captioned Potential Payments Upon Termination or Change of Control.

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 us or solicit our 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 a change of control, the long-term incentive programs, other than the 2011 2013 program, provide for the vesting and payment of performance units and RSUs, pro rata based on the number of days of employment during the allocable performance period, if the executive remains employed through the original three-year performance period. In addition, performance units and RSUs will vest and pay out at target, without proration, if the executive's employment terminates involuntarily in conjunction with the change of control, unless the Committee determines otherwise. Under the 2011 2013 program, in the event of a change of control, all outstanding performance shares will be converted to RSUs assuming a target level of performance. These RSUs will vest according to the schedule that applies to the RSU component already granted as part of the 2011 2013 program.

Finally, in the event of a change of control, the Deferral Plan provides for the immediate vesting of any employer matches. These matches and any associated executive officer deferrals will be paid in a lump sum without respect to the executive s original election.

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

With respect to the Company s pending merger with NSTAR, Mr. Shivery is not entitled to severance benefits because he ceased being entitled to such benefits upon attaining age 65. Messrs. McHale and Butler are entitled to severance benefits upon a qualifying termination of employment without regard to whether the merger is completed because the merger does not constitute a change in control within the meaning of their employment agreements. Messrs. Olivier and Muntz will be entitled to benefits under the Special Severance Program in the event of a qualifying termination of employment within two years following the approval by the Company s shareholders of the proposed merger. Pursuant to a supplemental agreement between the Company and Mr. Olivier, Mr. Olivier is also entitled to a special retirement payment upon a qualifying termination of employment within two years following the approval by the Company s shareholders of the merger. Mr. Robb will be entitled to benefits under his employment agreement in the event of a qualifying termination of employment within two years following the approval by the Company s shareholders of the merger.

TAX AND ACCOUNTING CONSIDERATIONS

Tax Considerations. All executive compensation for 2011 was fully deductible by us for federal income tax purposes, except for approximately $109,000 paid to Mr. Shivery, consisting primarily of RSU distributions.

Section 162(m) of the Internal Revenue Code limits the tax deduction for compensation paid to a Company s CEO and certain other executives. We are 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 for us, Mr. Shivery agreed, for as long as it is beneficial to us, to defer the distribution to him of common shares in respect of all vested RSUs until the calendar year after he leaves the Company, at which time Section 162(m) will no longer apply to him. The non-deductible RSU distributions for Mr. Shivery in 2011 described above relate to RSUs granted before Mr. Shivery was elected as our 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, our 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 we are 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, 2011. Forfeitures are estimated, and the compensation cost of awards 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.

COMPENSATION COMMITTEE REPORT

The Compensation Committee of the Northeast Utilities Board of Trustees has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with Northeast Utilities management. Based on this review and discussion, the Compensation Committee has recommended to the Board of Trustees that the Compensation Discussion and Analysis be included in NU s proxy statement for the 2012 annual meeting of shareholders and our Annual Report on Form 10-K.

The Compensation Committee

John S. Clarkeson, Chair

Sanford Cloud, Jr.

Elizabeth T. Kennan

Kenneth R. Leibler

Dennis R. Wraase

February 22, 2012

SUMMARY COMPENSATION TABLE

The table below summarizes the total compensation paid or earned by NU s Chairman of the Board, President and Chief Executive Officer (CEO), Executive Vice President and Chief Financial Officer (CFO) and the three other most highly compensated executive officers other than the CEO and CFO who were serving as executive officers of NU at the end of 2011, and James A. Muntz, President Transmission of NUSCO, who was appointed to serve as President and Chief Operating Officer of CL&P on November 18, 2011 until a permanent successor is elected (collectively, the Named Executive Officers or NEOs). In the table, Messrs. Shivery, Olivier and McHale are NEOs for both NU and CL&P, Mr. Robb is an NEO of NU only, and Mr. Muntz is an NEO of CL&P only. 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, 2011. The compensation shown for each Named Executive Officer was for all services in all capacities to NU and its subsidiaries. All salaries, annual incentive amounts and long-term incentive amounts shown for each Named Executive Officer were paid for all services rendered to NU and its subsidiaries in all capacities.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Stock Awards ($) (3)	Option Awards ($) (4)	Non-Equity Incentive Plan Compensation ($) (5)	Change in Pension Value and Non Qualified Deferred Compensation Earnings ($) (6)	All Other Compensation ($) (7)	Total ($)
Charles W.									
Shivery (8)	2011	1,063,270		5,879,275		Annual:	1,158,298	31,898	9,685,241
Chairman of						Long-Term: 1,552,500			
the Board,						Total: 1,552,500			
President and	2010	1,035,000		1,905,964		Annual: 1,987,200	1,525,310	31,050	8,254,374
Chief						Long-Term: 1,769,850			
Executive						Total: 3,757,050			
Officer of NU	2009	1,035,000		1,574,915		Annual: 1,645,650	1,812,023	31,050	7,773,638
and Chairman						Long-Term: 1,635,000			
of the						Total: 3,280,650			
Regulated									
companies									
David R. McHale	2011	537,721		835,141		Annual:	798,025	16,132	2,580,769
Executive						Long-Term: 393,750			
Vice						Total: 393,750			
President and	2010	525,000		2,484,707		Annual: 608,517	934,059	15,750	4,995,533
Chief						Long-Term: 427,500			
Financial						Total: 1,036,017			
Officer of NU	2009	524,520		399,436		Annual: 555,728	1,038,268	7,350	2,893,177
and the						Long-Term: 367,875			
Regulated						Total: 923,603			
companies									
	2011	565,548		879,174		Annual:	724,796	16,966	2,598,984

Leon J. Olivier Executive Vice				Long-Term:	412,500			
				Total:	412,500			
President and Chief Operating	2010	550,000	2,007,381	Annual:	601,494	699,343	16,500	4,255,906
				Long-Term:	381,188			
				Total:	982,682			
Officer of NU and Chief Executive Officer of the Regulated companies	2009	550,000	418,459	Annual:	558,415	219,565	16,500	2,086,533
				Long-Term:	323,594			
				Total:	882,009			
Gregory B. Butler	2011	417,508	648,701	Annual:		553,436	7,350	1,932,236
Senior Vice President and				Long-Term:	305,241			
				Total:	305,241			
General Counsel of NU and the	2010	406,988	1,875,695	Annual:	458,320	472,066	7,350	3,568,394
				Long-Term:	347,975			
				Total:	806,295			
Regulated companies	2009	406,988	309,666	Annual:	414,009	503,614	7,350	1,958,496
				Long-Term:	316,870			
				Total:	730,878			
James B. Robb	2011	409,692	424,224	Annual:			42,041	1,075,957
				Long-Term:	200,000			
				Total:	200,000			
Senior Vice President Enterprise	2010	400,000	1,246,211	Annual:	339,000		45,243	2,258,454
				Long-Term:	228,000			
				Total:	567,000			
Planning & Development NUSCO	2009	400,000	202,896	Annual:	316,500		44,237	963,633
				Long-Term:				
				Total:	316,500			

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James A Muntz (9) President -Transmission, NUSCO, President and Chief Operating Officer, CL&P; (Named Executive Officer of CL&P only).	2011	409,692	424,224	Annual: Long-Term: Total:	297,641 200,000 497,641	636,928	12,291	1,980,776

(1)

Includes amounts deferred in 2011 by the Named Executive Officers under the Deferral Plan, as follows: Mr. Shivery: $31,898; Mr. McHale: $8,604; Mr. Olivier: $113,110; Mr. Robb: $8,194; and Mr. Muntz: $102,423. For more information, see the Executive Contributions in the Last Fiscal Year column of the Non-Qualified Deferred Compensation Plans Table.

(2)

No discretionary bonus awards were made to any of the Named Executive Officers in the fiscal years ended 2009, 2010 and 2011.

(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 2009, 2010 and 2011, certain Named Executive Officers were granted RSUs that vest in equal annual installments over three years as long-term incentive compensation. We deferred the distribution of common shares upon vesting of RSUs granted to Mr. Shivery until 2013, the calendar year after the year in which his employment terminates. 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 our 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 2011, the Named Executive Officers were granted performance shares as long-term compensation. These performance shares will vest on December 31, 2013, 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: $3,611,257; Mr. McHale: $912,516; Mr. Olivier: $960,609; Mr. Butler: $708,770; Mr. Robb: $463,500; and Mr. Muntz: $463,500.

On February 8, 2011, the Board of Trustees approved a special grant of 76,406 RSUs to Mr. Shivery to recognize the critical role he has had and will play in the successful leadership of the Company through the close of the pending merger with NSTAR and as nonexecutive Chairman of the Board during the post-merger integration period. The RSUs will vest eighteen months after the closing of the merger with NSTAR, coinciding with Mr. Shivery s commitment to remain as nonexecutive Chairman of the Board through that date. If Mr. Shivery dies or becomes disabled prior to the vesting date, then the RSUs will vest as of the date of death or disability. If Mr. Shivery does not serve on the Board through eighteen months after the merger closes, then the RSUs will be forfeited.

(4)

We did not grant stock options to any of the Named Executive Officers in 2011. We have not granted any stock options since 2002.

(5)

Includes payments to the Named Executive Officers under the 2011 Annual Incentive Program (Mr. Shivery: $0; Mr. McHale: $0; Mr. Olivier: $0; Mr. Butler: $0; Mr. Robb: $0; and Mr. Muntz: $297,614). Also includes performance cash payments under the 2009 2011 Long-Term Incentive Program (Mr. Shivery: $1,552,500; Mr. McHale: $393,750; Mr. Olivier: $412,500; Mr. Butler: $305,241; Mr. Robb: $200,000; and Mr. Muntz: $200,000). Performance goals under the 2011 Annual Incentive Program were communicated to each officer by the CEO or, in the case of the CEO, jointly by the Compensation Committee and Corporate Governance Committee, during the first 90 days of 2011. The Compensation Committee acting jointly with the Corporate Governance Committee determined the extent to which these goals were satisfied (based on input from the CEO, in the case of the other Named Executive Officers) in February 2012. Performance goals under the 2009 2011 Long-Term Incentive Program were communicated to each officer by the CEO or, in the case of the CEO, jointly by the Compensation Committee and Corporate Governance Committee, during the first 90 days of 2009. The Compensation Committee determined the extent to which the long-term goals were satisfied in February 2012.

(6)

Includes the actuarial increase in the present value from December 31, 2010 to December 31, 2011 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 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, 2011. 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 our defined benefit pension plan. There were no above-market earnings on deferrals in 2011.

(7)

Includes matching contributions of $7,350 allocated by us to the account of each of the Named Executive Officers under the 401k Plan; Med-Vantage employer contributions (Mr. Robb: $1,000); qualified K-Vantage employer contributions under the 401k Plan (Mr. Robb: $11,025); nonqualified K-Vantage employer contributions under the Deferral Plan (Mr. Robb: $22,666); and employer matching contributions under the Deferral Plan for the Named Executive Officers who deferred part of their salary in the fiscal year ended December 31, 2010 (Mr. Shivery: $24,548; Mr. McHale: $8,782; Mr. Olivier: $9,616; Mr. Robb: $4,941; and Mr. Muntz: $4,941). Mr. Butler did not participate in the Deferral Plan in 2011.

(8)

Mr. Shivery s 2011 total compensation includes the special grant of 76,406 RSUs valued at $2,574,118 as described in footnote 3 above. Excluding the value of this special grant, Mr. Shivery received total compensation of $7,111,123 for 2011.

(9)

Mr. Muntz did not meet the requirements for inclusion in the Summary Compensation Table and was not a CL&P Named Executive Officer for 2009 or 2010. Mr. Muntz became a CL&P Named Executive Officer in 2011, following his appointment to serve as President and Chief Operating Officer of CL&P effective November 18, 2011.

GRANTS OF PLAN-BASED AWARDS DURING 2011

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, 2011. The table also discloses the underlying stock awards and the grant date for equity-based awards. We have not granted any stock options since 2002. Accordingly, we did not grant stock options to any of the Named Executive Officers in 2011.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards (1)				
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**All Other Stock Awards: Number of Shares of Stock or Units (#) (2)**	**Grant Date Fair Value of Stock and Option Awards**

								($) (3)
Charles W. Shivery								
Annual Incentive (4)	2/8/2011	535,000	1,070,000	2,140,000				
Long-Term Incentive (5)	2/8/2011				73,579	110,369	24,526	3,305,157
Special Equity Grant (6)	2/8/2011						76,406	2,574,118
David R. McHale								
Annual Incentive (4)	2/8/2011	174,759	349,519	699,038				
Long-Term Incentive (5)	2/8/2011				18,592	27,888	6,197	835,141
Leon J. Olivier								
Annual Incentive (4)	2/8/2011	183,803	367,606	735,213				
Long-Term Incentive (5)	2/8/2011				19,572	29,358	6,524	879,174
Gregory B. Butler								
Annual Incentive (4)	2/8/2011	135,690	271,380	542,760				
Long-Term Incentive (5)	2/8/2011				14,441	21,661	4,814	648,701
James B. Robb								
Annual Incentive (4)	2/8/2011	102,423	204,846	409,692				
Long-Term Incentive (5)	2/8/2011				9,444	14,166	3,148	424,224
James A. Muntz								
Annual Incentive (4)	2/8/2011	102,423	204,846	409,692				
Long-Term Incentive (5)	2/8/2011				9,444	14,166	3,148	424,224

(1)

Reflects the number of performance shares granted to each of the Named Executive Officers on February 8, 2011 under the 2011 2013 Long-Term Incentive Program. Performance shares were granted with a three-year Performance Period that ends on December 31, 2013. 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. Holders of performance shares are eligible to receive dividend equivalent units on outstanding performance shares held by them to the same extent that dividends are declared and paid on our 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 performance shares. The Annual Incentive Program does not include an equity component.

(2)

Reflects the number of RSUs granted to each of the Named Executive Officers on February 8, 2011 under the 2011 2013 Long-Term Incentive Program. RSUs vest in equal installments on February 25, 2012, 2013 and 2014. Except for Messrs. Shivery and Robb, we 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, we 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 the Company and (ii) January of the calendar year after he leaves the Company. For Mr. Robb, we will distribute common shares after reduction for applicable withholding taxes, in respect of vested RSUs beginning the earlier of (i) fifteen years beyond the vesting date or (ii) six months after he leaves the Company. Holders of RSUs are eligible to receive dividend equivalent units on outstanding RSUs held by them to the same extent that dividends are declared and paid on our 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. The Annual Incentive Program does not include an equity component.

Also includes the number of RSUs granted to certain Mr. Shivery on February 8, 2011 in connection with the merger with NSTAR. See note 3 to the Summary Compensation Table.

(3)

Reflects the grant-date fair value, determined pursuant to generally accepted accounting principles, of: (i) RSUs and performance shares granted to the Named Executive Officers on February 8, 2011, under the 2011 2013 Long-Term Incentive Program; and (ii) RSUs granted to the Mr. Shivery on February 8, 2011 in connection with the merger with NSTAR. The Annual Incentive Program does not include an equity component.

(4)

Amounts reflect the range of potential payouts, if any, under the 2011 Annual Incentive Program for each Named Executive Officer, as described in the Compensation Discussion and Analysis. The payment in 2012 for performance in 2011 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.

(5)

Reflects the range of potential payouts, if any, pursuant to performance share awards under the 2011 2013 Long-Term Incentive Program, as described in the Compensation Discussion and Analysis. No performance share awards were made in 2011 under the 2011 2013 Long-Term Incentive Program.

(6)

Reflects the number of RSUs granted to Mr. Shivery on February 8, 2011 in connection with the merger with NSTAR. See note 3 to the Summary Compensation Table.

EQUITY GRANTS OUTSTANDING AT DECEMBER 31, 2011

The following table sets forth option, RSU and performance share grants outstanding at the end of our fiscal year ended December 31, 2011 for each of the Named Executive Officers. All outstanding options were fully vested as of December 31, 2011.

	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)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(5)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(6)
Charles W. Shivery	29,024	$18.90	06/11/2012	137,804	4,970,590	124,315	4,484,042
David R. McHale				81,611	2,943,708	31,458	1,134,690
Leon J. Olivier				65,684	2,369,222	33,053	1,192,222
Gregory B. Butler				61,594	2,221,696	24,415	880,649
James B. Robb				40,925	1,476,164	15,980	576,399
James A. Muntz				18,415	664,229	15,980	576,399

(1)

We have 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 additional 61,617 unvested RSUs will vest on February 25, 2012 (Mr. Shivery: 31,331; Mr. McHale: 7,938; Mr. Olivier: 8,327; Mr. Butler: 6,157; Mr. Robb: 3,932; and Mr. Muntz: 3,392). An additional 37,854 unvested RSUs will vest on February 25, 2013 (Mr. Shivery: 19,188; Mr. McHale: 4,859; Mr. Olivier: 5,101; Mr. Butler: 3,770; Mr. Robb: 2,468; and Mr. Muntz: 2,468). An additional 10,832 unvested RSUs will vest on November 2, 2012 (Mr. Muntz: 10,832). An additional 16,637 unvested RSUs will vest on February 25, 2014 (Mr. Shivery: 8,437; Mr. McHale: 2,132; Mr. Olivier: 2.244; Mr. Butler: 1,656; Mr. Robb: 1,084; and Mr. Muntz: 1,084).

In connection with the merger with NSTAR, on November 16, 2010, the Board of Trustees established a retention pool in an aggregate amount of $10 million to be allocated to key employees, including some or all executive officers, to help ensure their continued dedication to the Company both before and after completion of the merger. Awards were in the form of RSUs and generally vest subject to three years of continuous service following completion of the merger. Full payment will also be made if an eligible executive dies, becomes disabled, or is terminated by the Company without cause before the end of the retention period, in which case the retention payment will be reduced by the amount of any cash severance payable to the executive upon or during the year following termination. An additional 193,854 unvested RSUs granted pursuant to the retention pool will vest subject to three years of continuous service following completion of the merger with NSTAR (Mr. McHale: 64,618; Mr. Olivier: 48,463; Mr. Butler: 48,463; and Mr. Robb: 32,310). Mr. Muntz did not participate in this program.

(4)

The market value of RSUs is determined by multiplying the number of RSUs by $36.07, the closing price per share of common shares on December 30, 2011, the last trading day of the year.

(5)

Reflects the target payout level for 2011 and 2010 performance shares. Payouts for 2011 and 2010 performance shares will be based on actual performance. Performance shares are described in the CD&A and footnote (1) to the Grants of Plan-Based Awards table. Performance shares vest following a three-year performance period to the extent targets are achieved. Performance shares are also discussed in the CD&A under Performance Units above. A total of 95,477 unearned performance shares will vest on December 31, 2012 (Mr. Shivery: 48,386; Mr. McHale: 12.272; Mr. Olivier: 12,856; Mr. Butler: 9,513; Mr. Robb: 6,234; and Mr. Muntz: 6,234). An additional 149,706 unearned performance shares will vest on December 31, 2013 (Mr. Shivery: 75,929; Mr. McHale: 19,186; Mr. Olivier: 20,197; Mr. Butler: 14,902; Mr. Robb: 9,746; and Mr. Muntz: 9,746).

(6)

The market value is determined by multiplying the number of performance shares in the adjacent column by $36.07, the closing price per share of common shares on December 30, 2011, the last trading day of the year.

OPTIONS EXERCISED AND STOCK VESTED IN 2011

The following table reports amounts realized on equity compensation during the fiscal year ended December 31, 2011. None of the Named Executive Officers exercised options in 2011. The Stock Awards columns report the vesting of RSU grants to the Named Executive Officers in 2011.

	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			49,119	1,612,086
David R. McHale			11,766	386,160
Leon J. Olivier			11,369	373,131
Gregory B. Butler			8,758	287,438
James B. Robb			5,961	195,640
James A. Muntz			20,931	686,955

(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	2008 Program	2009 Program	2010 Program
Charles W. Shivery	26,224	12,143	10,752
David R. McHale	6,138	2,985	2,643
Leon J. Olivier	5,473	3,127	2,769
Gregory B. Butler	4,396	2,313	2,049
James B. Robb	3,012	1,564	1,385
James A. Muntz	1,947	1,516	1,342

In all cases, we reduce the distribution of common shares by that number of shares valued in an amount sufficient to satisfy tax withholding obligations, which amount we distribute 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 for all amounts is based on $32.82 per share, the closing price of common shares on February 25, 2011. This value includes the value of vested RSUs for which the distribution of common shares is currently deferred. Includes the vesting of 16,125 shares for Mr. Muntz on November 2, 2011. Mr. Muntz was granted 24,096 RSUs on November 7, 2008 to vest November 2, 2011 and November 2, 2013.

PENSION BENEFITS IN 2011

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, 2011 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 became eligible to receive unreduced benefits at age 65, Messrs. McHale and Olivier are eligible to receive unreduced benefits at age 60, Mr. Butler is eligible to receive unreduced benefits at age 62, and Mr. Muntz is eligible to receive unreduced benefits at age 65. 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, 2011 were used to determine the benefits under each plan. The accrued benefits reflect actual compensation (both salary and incentives) earned during 2011. 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 2012 payment pursuant to the 2011 Annual Incentive Program was reflected in the 2011 plan compensation. We determined the present value of the benefit at retirement age by using the discount rate of 5.57% under Statement of Financial Accounting Standards No. 87 for the 2011 fiscal year end measurement (as of December 31, 2011). 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 2012 with projection scale AA (same table used for financial reporting under FAS 87). Additional assumptions appear under the caption entitled Management s Discussion and Analysis and Results of Operations in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

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	9.6	387,825	
	Supplemental Plan	9.6	7,566,228	
	Other Special Benefit	12.6	2,490,831	
David R. McHale	Retirement Plan	30.3	918,365	
	Supplemental Plan	30.3	3,541,056	

Leon J. Olivier (2)	Retirement Plan	12.8	516,123	
	Supplemental Plan	10.3		
	Other Special Benefit	10.3	3,101,153	
	Other Special Benefit	32.3	1,281,935	105,966
Gregory B. Butler	Retirement Plan	15.0	441,905	
	Supplemental Plan	15.0	2,287,874	
James B. Robb	Retirement Plan			
	Supplemental Plan			
James A. Muntz (3)	Retirement Plan	10.1	219,801	
	Supplemental Plan	10.1	648,809	
	Other Special Benefit	31.1	1,419,229	

(1)

Mr. Shivery s actual service with us totaled 9.6 years at December 31, 2011. 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 (ii) benefits otherwise payable from the Retirement Plan and the Supplemental Plan. The value of the additional three years of service on December 31, 2011 was approximately $2,490,831.

(2)

Mr. Olivier was employed with Northeast Nuclear Energy Company, one of our 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 us 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, Mr. Olivier became eligible during 2011 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 us, 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. Amounts reported in the table assume the termination of his employment with our consent on December 31, 2011, and payment of the lump sum benefit of $3,617,276 offset by Retirement Plan benefits.

(3)

Mr. Muntz s actual service with us totaled 10 years at December 31, 2011. However, Mr. Muntz s employment agreement provides that upon attaining age 55, he is entitled to a special annual retirement benefit in the event his employment terminates for any reason other than cause. This special annual benefit confers credit upon Mr. Muntz for 21 years of service with his previous employer, Exelon Corporation (Exelon), when calculating his pension, and offsets the resulting benefit by: (i) an amount approximating his annual Exelon pension benefit, and (ii) the benefit otherwise payable from the Retirement Plan and the Supplemental Plan excluding such additional service credit. This special annual benefit provides for an annuity payable at the same time and in the same form as his Retirement Plan or Supplemental Plan benefit (as applicable). Mr. Muntz s employment agreement also provides that in the event of termination of his employment for any reason other than cause before he attains age 55, he will be entitled to a special lump sum payment equal to the greater of: (i) the actuarial equivalent lump sum present value of the special annual retirement benefit referred to above ($1,419,229), or (ii) a pre-established dollar amount ($335,000 using a December 31, 2011 termination date) increasing with and linearly interpolated based on actual age at termination.

NONQUALIFIED DEFERRED COMPENSATION IN 2011

Name	Executive Contributions in Last FY ($)(1)	Registrant Contributions in Last FY ($) (2)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($) (3)	Aggregate Balance at Last FYE ($) (4)
Charles W. Shivery	1,895,242	24,548	1,675,878	(109,106)	14,311,086
David R. McHale	8,604	8,732	49,509	(132,570)	279,759
Leon J. Olivier	113,110	9,616	(68,087)	(199,810)	1,757,016
Gregory B. Butler			59,117	(215,376)	364,754
James B. Robb	46,602	27,607	77,882		322,792
James A. Muntz	102,423	4,941	310,556		3,564,982

(1)

Includes deferrals by the Named Executive Officers under the 2011 Deferral Plan (Mr. Shivery: $31,898; Mr. McHale: $8,604; Mr. Olivier: $113,110; Mr. Robb: $8,194; and Mr. Muntz: $102,423). 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, but will become fully vested upon a change of control.

All other amounts relate to the value of common shares, the distribution of which was either automatically deferred upon vesting of underlying RSUs pursuant to the terms of the respective Long-Term Incentive Programs, or pursuant to the Named Executive Officer s deferral election, calculated using $32.82 per share, the closing price of the common shares on February 25, 2011, the vesting date. For more information, see the footnotes to the Options Exercised and Stock Vested Table.

(2)

Includes employer matching contributions made to the Deferral Plan as of December 31, 2011 and posted on January 31, 2012, as reported in the All Other Compensation column of the Summary Compensation Table (Mr. Shivery: $24,548; Mr. McHale: $8,782; Mr. Olivier: $9,616; and Mr. Robb: $4,941). The employer matching contribution is deemed to be invested in common shares but is paid in cash at the time of distribution. Also includes nonqualified K-Vantage employer contributions made to the Deferral Plan during fiscal year 2011 (Mr. Robb: $22,666).

(3)

Includes distributions to Named Executive Officers under the Deferral Plan during fiscal year 2011 pursuant to their deferral elections (Mr. Olivier: $19,376); plus the value of previously vested deferred RSUs distributed in 2011, pursuant to the Named Executive Officer s deferral election, valued at distribution at $32.82 per share, the closing price of NU common shares on February 25, 2011.

(4)

Includes the total market value of Deferral Plan balances at December 31, 2011, plus the value of vested RSUs for which the distribution of common shares is currently deferred, based on $36.07 per share, the closing price of NU common shares on December 30, 2011, the last trading day of the year.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE OF CONTROL

Generally, a change of control means a change in ownership or control effected through (i) the acquisition of 20% or more of the combined voting power of common shares or other voting securities, (ii) a change in the majority of the 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% (75% for Messrs. Olivier, Robb and Muntz) 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, Robb and Muntz) 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.

In the event of a change of control, the NEOs are each entitled to receive compensation and benefits following either termination of employment without cause or upon termination of employment by the executive for good reason 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, Robb and Muntz), or the transfer of the executive to an office location more than 50 miles from his principal place of business immediately prior to a change of control.

With respect to the proposed merger with NSTAR, none of the Named Executive Officers will be entitled to receive any additional compensation and benefits in the absence of a termination of employment for cause or for good reason within two years (for Messrs. Olivier, Robb and Muntz) after shareholder approval of the merger.

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, 2011, 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 by the executive under the Deferral Plan;

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Vested matching contributions under the Deferral Plan;

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Pay for unused vacation; and

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

I.

Post-Employment Compensation: Termination for Cause

	Shivery	**McHale**	**Olivier**	**Butler**	**Robb**	**Muntz**
Type of Payment	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
Incentive Programs						
Annual Incentives						
Performance Cash						
Performance Shares						
RSUs (1)	13,662,054	243,545	294,403	338,192	146,012	
Pension and Deferred Compensation						
Supplemental Plan (2)	4,323,395					
Special Retirement Benefit (3)			1,553,877			
Deferral Plan (4)	553,112	16,467	1,426,222	26,546	141,732	3,546,752
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	18,538,561	260,012	3,274,502	364,738287,744	3,546,752

(1)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2011, had been deferred upon vesting and remained deferred. Excludes retention pool RSU grants.

(2)

Represents the actuarial present value at the end of 2011 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.

(3)

Represents the actuarial present values at the end of 2011 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 2011 of benefits payable to each Named Executive Officer upon termination.

(4)

Represents the vested Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2011.

II.

Post-Employment Compensation: Voluntary Termination

	Shivery	**McHale**	**Olivier**	**Butler**	**Robb**	**Muntz**
Type of Payment	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
Incentive Programs						
Annual Incentives (1)						297,641
Performance Cash (2)	4,269,384	393,750	790,625	305,241	200,000	200,000
Performance Shares (3)	3,902,291		478,238			
RSUs (4)	15,788,560	243,545	519,812	338,192	146,012	
Pension and Deferred Compensation						
Supplemental Plan (5)	7,566,228					
Special Retirement Benefit (6)	2,490,831		1,533,877			
Deferral Plan (7)	553,112	16,467	1,426,222	26,546	141,732	3,546,752
Other Benefits						

Health and Welfare Benefits (8)	104,687					
Perquisites						
Separation Payments						
Excise Tax & Gross-Up						
Separation Payment for Non-Compete Agreement						
Separation Payment for Liquidated Damages						
Total	34,675,093	653,762	4,748,774	669,979	487,744	4,044,393

(1)

Represents the actual 2011 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis in this Item 11.

(2)

Represents the actual performance cash award under the 2009 2011 Long-Term Incentive Program for each Named Executive Officer. Also includes, for Messrs. Shivery and Olivier, performance cash awards under the 2010 2012 Long-Term Incentive Program, because each of them would be considered to be a retiree under those programs. Full grant amounts are awarded to Mr. Shivery because he has attained age 65, while amounts for Mr. Olivier are prorated for time worked in each three-year performance period, determined as described in the Compensation Discussion and Analysis in this Item 11.

(3)

Includes, for Messrs. Shivery and Olivier, performance share awards under the 2010 2012 and 2011 2013 Long-Term Incentive Programs, because each of them would be considered to be a retiree under those programs. Full grant amounts are awarded to Mr. Shivery because he has attained age 65, while amounts for Mr. Olivier are prorated for time worked in the three-year performance period, determined as described in the Compensation Discussion and Analysis in this Item 11.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs that, as of the end of 2011, 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, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination, and time worked during the vesting period. Full grant amounts are distributed without proration to Mr. Shivery because he has attained age 65. The values were calculated by multiplying the number of RSUs by $36.07, the closing price of NU common shares on December 30, 2011, the last trading day of the year. Excludes retention pool RSU grants, which would not vest upon voluntary termination.

(5)

Represents the actuarial present value at the end of 2011 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.

(6)

Represents the actuarial present values at the end of 2011 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon voluntary termination were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,050,000 offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon voluntary termination. Pension amounts reflected in the table are present values at the end of 2011 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.

(7)

Represents the vested Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2011.

(8)

Represents the costs to the Company estimated by our benefits consultants as of the end of 2011 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 ($)**	**Muntz ($)**
Incentive Programs						
Annual Incentives (1)						297,641
Performance Cash (2)	4,269,384	754,683	790,625	585,048	200,000	383,329
Performance Shares (3)	3,902,291	455,521	478,238	353,434		231,391
RSUs (4)	15,788,560	782,611	859,656	755,919	531,939	273,483
Pension and Deferred Compensation						
Supplemental Plan (5)	7,566,228	3,527,585		1,298,588		648,809
Special Retirement Benefit (6)	2,490,831	2,902,412	3,101,153	2,287,874		1,419,229
Deferral Plan (7)	553,112	16,467	1,426,222	26,546	141,732	3,546,752
Other Benefits						

Health and Welfare Benefits (8)	104,687	69,125		67,851		
Perquisites (9)		7,000		7,000		
Separation Payments						
Excise Tax & Gross-Up						
Separation Payment for Non-Compete Agreement (10)		900,487		693,019	318,000	309,000
Separation Payment for Liquidated Damages (11)		900,487		693,019	318,000	309,000
Total	34,675,093	10,316,378	6,655,894	6,768,298	1,509,671	7,418,634

(1)

Represents the actual 2011 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis in this Item 11.

(2)

Represents the actual performance cash award under the 2009 2011 Long-Term Incentive Program for each Named Executive Officer. Also includes, for Messrs. Shivery, McHale, Olivier, and Butler, performance cash awards under the 2010 2012 Long-Term Incentive Program. Full grant amounts are awarded to Mr. Shivery because he has attained age 65, while amounts for Messrs. McHale, Olivier and Butler are prorated for time worked in each three-year performance period, because each of them would be considered to be a retiree under those programs, determined as described in the Compensation Discussion and Analysis in this Item 11.

(3)

Includes, for Messrs. Shivery, McHale, Olivier and Butler, performance share awards under the 2010 2012 and 2011 2013 Long-Term Incentive Programs. Full grant amounts are awarded to Mr. Shivery because he has attained age 65, while amounts for Messrs. McHale, Olivier and Butler 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 in this Item 11.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs and the retention program that, as of the end of 2011, 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 the long-term incentive programs, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination, and time worked during the vesting period. Full grant amounts are distributed without proration to Mr. Shivery because he has attained age 65. Under the retention program, RSUs vest fully upon termination without cause of the Named Executive Officers and the value is reduced by any separation payments as described in notes 10 and 11. The values were calculated by multiplying the number of RSUs by $36.07, the closing price of NU common shares on December 30, 2011, the last trading day of the year.

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(5)

Represents the actuarial present value at the end of 2011 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.

(6)

Represents the actuarial present values at the end of 2011 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 were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $3,101,153 offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon an involuntary termination other than for cause. As described in more detail in the narrative accompanying the Pension Benefits Table, pursuant to the employment agreement with Mr. Muntz, in the event of our termination of his employment for any reason other than cause before he attains age 55, he is entitled to a lump sum payment equal to the actuarial equivalent lump sump present value of a special annual retirement benefit calculated with the addition of 21 years of service and offset by: (i) an amount approximating his pension with a previous employer, and (ii) the benefit otherwise payable from the Retirement Plan and the Supplemental Plan. Pension amounts reflected in the table are present values at the end of 2011 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.

(7)

Represents the vested Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2011.

(8)

Represents the costs to the Company estimated by our benefits consultants as of the end of 2011 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. McHale and Butler is entitled to receive active health and welfare 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, plus tax gross-up with respect to such taxable subsidized coverage and are eligible to receive qualified benefits under the retiree health plan. Mr. Shivery is entitled to receive retiree health benefits under his employment agreement. Therefore, the amount reported in the table for Messrs. McHale and Butler represents (a) the value of 24 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. Shivery represents (a) the value of lifetime retiree health coverage, plus (b) tax gross-up payments thereon.

(9)

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

(10)

Represents payments made as consideration for agreements by each of Messrs. McHale, Butler, Robb and Muntz not to compete with the Company following termination. Employment or other agreements with Messrs. McHale, Butler, Robb and Muntz provide for a lump-sum payment in an amount equal to the sum (one-half of the sum for Messrs. Robb and Muntz) of their 2011 annual salary plus annual incentive award at target (2010 for Mr. Robb). These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

(11) Represents severance payments to Messrs. McHale, Butler, Robb and Muntz paid in addition to the non-compete agreement payments described in note 10. This payment is an amount equal to the sum (one-half of the sum for Messrs. Robb and Muntz) of their actual base salary paid in 2011 plus the annual incentive award at target (2010 for Mr. Robb). 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 ($)	Muntz ($)
Incentive Programs						
Annual Incentives (1)						297,641
Performance Cash (2)	4,269,384	754,683	790,625	585,048	383,329	383,329
Performance Shares (3)	3,902,291	455,521	478,238	353,434	231,391	231,391
RSUs (4)	15,788,560	2,843,641	2,323,709	2,803,403	1,337,400	109,144
Pension and Deferred Compensation						
Supplemental Plan (5)	7,566,228	3,527,585		1,298,558		648,809
Special Retirement Benefit (6)	2,490,831		3,101,153			
Deferral Plan (7)	553,112	16,467	1,426,222	26,546	141,732	3,546,752
Other Benefits						
Health and Welfare Benefits (8)	104,687					
Perquisites						
Separation Payments						
Excise Tax & Gross-Up						
Separation Payment for Non-Compete Agreement						
Separation Payment for Liquidated Damages						
Total	34,675,093	7,597,897	8,119,947	5,067,329	2,093,852	5,217,066

(1)

Represents the actual 2011 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis in this Item 11.

(2)

Represents the actual performance cash award under the 2009 2011 Long-Term Incentive Program determined as described in the Compensation Discussion and Analysis in this Item 11, plus performance cash awards at target under the 2010 2012 Long-Term Incentive Program prorated for time worked in each three-year performance period.

(3)

Represents the performance share award at target under the 2010 2012 and 2011 2013 Long-Term Incentive Programs prorated for time worked in the three-year performance period, as described in the Compensation Discussion and Analysis in this Item 11.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs and the retention program that, as of the end of 2011, 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 the long-term incentive programs, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination, and time worked during the vesting period. Under the retention program, RSUs vest fully upon termination due to disability of the Named Executive Officer. The values were calculated by multiplying the number of RSUs by $36.07, the closing price of NU common shares on December 30, 2011¸ the last trading day of the year.

(5)

Represents the actuarial present value at the end of 2011 of the benefit payable from the Supplemental Plan to each NEO other than Mr. Olivier. For purposes of valuing the pension benefits, we have assumed that each Named Executive Officer would remain on our Long Term Disability plan until the executive s first unreduced combined pension benefit age. Therefore, the numbers shown represent the actuarial present values at the end of 2011 of nonqualified pension benefits payable to each Named Executive Officer, assuming termination of employment at the earliest unreduced benefit age. The earliest unreduced benefit ages are different for each NEO based on employment agreement provisions and years of service, as follows: Mr. Shivery: immediately; Mr. McHale: age 55; Mr. Olivier: immediately; and Mr. Butler: age 62. 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.

(6)

Represents the actuarial present values at the end of 2011 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 $3,101,153, 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.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2011.

(8)

Represents the costs to the Company estimated by our benefits consultants as of the end of 2011 of providing post-employment welfare benefits to Mr. Shivery beyond those benefits that would be provided to a nonexecutive employee upon disability 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.

V.

Post-Employment Compensation: Death

Type of Payment	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Robb ($)**	**Muntz ($)**
Incentive Programs						
Annual Incentives (1)						297,641
Performance Cash (2)	4,269,384	754,683	790,625	585,048	383,329	383,329
Performance Shares (3)	3,902,291	455,521	478,238	353,434	231,391	231,391
RSUs (4)	15,788,560	2,843,641	2,323,709	2,803,403	1,337,400	109,144
Pension and Deferred Compensation						
Supplemental Plan (5)	3,858,776	3,527,585		1,298,558		648,809
Special Retirement Benefit (6)	1,270,324		3,214,047			1,419,229
Deferral Plan (7)	553,112	16,467	1,426,222	26,546	141,732	3,546,752
Other Benefits						
Health and Welfare Benefits (8)	61,988					
Perquisites						
Separation Payments						
Excise Tax & Gross-Up						
Separation Payment for Non-Compete Agreement						
Separation Payment for Liquidated Damages						
Total	29,704,435	7,597,897	8,119,947	5,067,329	2,093,852	5,217,066

(1)

Represents the actual 2011 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis in this Item 11.

(2)

Represents the actual performance cash award under the 2009 2011 Long-Term Incentive Program determined as described in the Compensation Discussion and Analysis above, plus performance cash awards at target under the 2010 2012 Long-Term Incentive Program prorated for time worked in each three-year performance period.

(3)

Represents the performance share awards at target under the 2010 2012 and 2011 2013 Long-Term Incentive Programs prorated for time worked in the three-year performance period, as described in the Compensation Discussion and Analysis in this Item 11.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs and the retention program that, as of the end of 2011, 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 the long-term incentive programs, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination upon death, and time worked during the vesting period. Under the retention program, RSUs vest fully upon termination due to death of the Named Executive Officer. The values were calculated by multiplying the number of RSUs by $36.07, the closing price of NU common shares on December 30, 2011, the last trading day of the year.

(5)

Represents the lump sum present value of pension payments from 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 2011 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 $3,214,047, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier s spouse upon death. Pursuant to the employment agreement with Mr. Muntz, a lump sum payment of $1,419,229 (calculated as described in note 3 to the Pension Benefits Table) would be payable to his estate upon death. Pension amounts reflected in the table are present values at the end of 2011 of benefits payable immediately to each Named Executive Officer s surviving spouse or estate. 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 2011.

(8)

Represents the costs to the Company estimated by our benefits consultants as of the end of 2011 of providing post-employment welfare benefits to the Mr. Shivery s surviving spouse beyond those benefits that would be provided to a nonexecutive employee s spouse upon the employee s death. Mr. Shivery s surviving spouse is entitled to receive retiree health benefits under Mr. Shivery s employment agreement. To the extent these benefits are taxable to Mr. Shivery s surviving spouse, she 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. McHale, Olivier, Butler and Robb include change of control benefits. Mr. Olivier and Mr. Muntz participate 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 us and on certain of our majority-owned subsidiaries. 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 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 principal place of business immediately prior to a change of control), then the executive officer will receive the benefits listed below, which receipt is conditioned upon delivery of a binding release of all legal claims against the Company:

.

A lump sum severance payment of two-times (one-times for Messrs. Olivier and Muntz 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 by us for three years (two years for Mr. Olivier and Mr. Muntz, none for Mr. Robb);

.

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 and Mr. Muntz, 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 performance units at target; and

.

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

The summaries of the employment agreements above do not purport to be complete and are qualified in their entirety by the actual terms and provisions of the employment agreements, copies of which have been filed as exhibits to our Annual Report on Form 10-K for the year ended December 31, 2011.

VI.

Post-Employment Compensation: Termination Following a Change of Control

	Shivery	**McHale**	**Olivier**	**Butler**	**Robb**	**Muntz**
Type of Payment	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
Incentive Programs						
Annual Incentives (1)						297,641
Performance Cash (2)	4,269,684	1,082,800	1,134,376	839,420	549,987	549,987
Performance Shares (3)	3,902,291	987,447	1,037,555	766,406	501,590	501,590
RSUs (4)	15,788,560	782,611	859,656	755,919	273,483	791,210
Pension and Deferred Compensation						
Supplemental Plan (5)	7,566,228	3,527,585		1,298,558		648,809
Special Retirement Benefit (6)	2,490,831	2,902,412	3,101,153	2,287,874		1,419,229
Deferral Plan (7)	553,112	16,467	1,426,222	26,546	141,742	3,546,752
Other Benefits						
Health and Welfare Benefits (8)	101,181	98,890	20,053	86,064		20,053
Perquisites (9)		8,500		8,500		
Separation Payments						
Excise Tax and Gross-Up (10)		4,001,955		2,767,501		
Separation Payment for Non-Compete Agreement (11)		900,487	939,262	693,019	309,000	618,000
Separation Payment for Liquidated Damages (12)		1,800,874	939,262	1,386,038	309,000	618,000
Total	34,671,887	16,110,028	9,457,539	10,915,845	2,084,802	9,011,271

(1)

Represents the actual 2011 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis in this Item 11.

(2)

Represents the actual performance cash award under the 2009 2011 Long-Term Incentive Program for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis beginning in this Item 11, plus performance cash awards at target for each Named Executive Officer under the 2010 2012 Long-Term Incentive Program.

(3)

Represents the performance share award at target for each Named Executive Officer under the 2010 2012 and 2011 2013 Long-Term Incentive Programs, determined as described in the Compensation Discussion and Analysis in this Item 11.

(4)

Represents values of all RSUs granted to the Named Executive Officers under our long-term incentive programs and the retention program that, as of the end of 2011, 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 the long-term incentive programs, RSUs vest fully on termination following a change of control. Under the retention program, RSUs vest fully upon termination without cause of the Named Executive Officer and the value is reduced by any separation payments as described in notes 11 and 12. For Messrs. McHale, Olivier and Butler, retention program RSU grants are fully eliminated when offset by separation payments. The values were calculated by multiplying the number of RSUs by $36.07, the closing price of NU common shares on December 30, 2011, the last trading day of the year.

(5)

Represents the actuarial present value at the end of 2011 of the benefit payable from the Supplemental Plan to Messrs. Shivery, McHale and Butler 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.

(6)

Represents the actuarial present values at the end of 2011 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 retirement were calculated with the addition of three 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 $3,101,153, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon termination following a Change in Control. Pursuant to the employment agreement with Mr. Muntz, a lump sump payment of $1,419,229 (calculated as described in note 3 to the Pension Benefit Table) would be payable in the event of our termination of his employment for any reason other than cause before he attains age 55. Pension amounts reflected in the table are present values at the end of 2011 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.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2011.

(8)

Represents the costs to the Company estimated by our benefits consultants as of the end of 2011 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. McHale and Butler is entitled to receive active health and welfare 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, plus tax gross-up with respect to such taxable subsidized coverage and are eligible for qualified benefits under the retiree health plan. Mr. Olivier and Mr. Muntz participate in the SSP and each is eligible for two years of active health benefits continuation plus gross-up payments on the value thereof. Mr. Shivery is entitled to receive retiree health benefits under his employment agreement. The amount reported in the table for Mr. McHale represents (a) the value of 36 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. Butler represents (a) the value of 36 months of employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) tax gross-up payments thereon, less (c) the value of 12 months of retiree health coverage at retiree rates. The amounts reported in the table for Mr. Olivier represents (a) the value of 24 months of employer contributions toward active health benefits, plus (b) tax gross-up payments thereon, less (c) the value of 24 months of retiree health coverage at retiree rates. The amount reported in the table for Mr. Shivery represents (a) the value of lifetime retiree health coverage, plus (b) tax gross-up payments thereon.

(9)

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

(10)

Represents payments made to offset costs to Messrs. 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 Messrs. Olivier, Robb and Muntz 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%.

(11)

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 2011 (2010 for Mr. Robb) plus annual incentive award at target. Agreements with each

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Named Executive Officer or the SSP 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.

(12)

Represents severance payments to each Named Executive Officer paid in addition to the non-compete agreement payments described in note 11. For Messrs. McHale, and Butler, this payment equals two-times the sum of the actual base salary paid in 2011 plus annual incentive award at target. For Mr. Olivier and Mr. Muntz, this payment equals the sum of the actual base salary paid in 2011 plus annual incentive award at target. For Mr. Robb this payment equals one-half of the sum of his actual base salary paid in 2010 plus annual incentive award at target. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

TRUSTEE COMPENSATION

The Compensation Committee determines compensation for the Trustees based on competitive market practices for the total value of compensation and the allocation of cash and equity. The Committee uses data obtained from similarly-sized general industry companies as guidelines for setting Trustee compensation. The compensation elements consist of an annual retainer, meeting fees and equity grants in the form of RSUs. The level of Trustee compensation established by the Committee enables us to attract Trustees who have a broad range of backgrounds and experiences.

In 2011, we paid an annual retainer to each Trustee who is not employed by us or our subsidiaries. We pay an additional retainer to our Lead Trustee and the chairs of each of the Audit, Compensation, Corporate Responsibility, Corporate Governance and Finance Committees. Each retainer was paid in four equal quarterly installments. We paid one-half of the value of the retainers payable to the chairs of each of the Audit and Compensation Committees in the form of common shares. The following table sets forth the amounts of non-employee Trustee retainers for 2011:

Retainer	**Annual Amount**
Annual Retainer (all Trustees)	$45,000
Lead Trustee	$50,000
Audit Committee Chair	$20,000
Compensation Committee Chair	$15,000
Corporate Responsibility Committee Chair	$7,500
Corporate Governance Committee Chair	$7,500
Finance Committee Chair	$10,000

During 2011, we paid each non-employee Trustee $1,500 for attendance in person or by telephone at each meeting of the full Board and each committee on which he or she served. In 2011, in addition to regularly scheduled meetings, the Board and various committees of the Board conducted meetings in connection with our pending merger with NSTAR and the impact of Tropical storm Irene and the October 29, 2011 snowstorm.

Under the Northeast Utilities Incentive Plan, each non-employee Trustee is eligible to receive share-based grants during each calendar year. On January 3, 2011, each non-employee Trustee was granted 3,000 RSUs under the Incentive Plan, all of which vested on January 10, 2012.

The share ownership guidelines set forth in the Company s Corporate Governance Guidelines required Trustees to attain, by January 2012, 7,500 common shares and/or RSUs, which have a fair market value equal to approximately five times the value of the current annual retainer; provided, however, that Trustees who join the Board after January 1, 2007 will be required to attain such shares no later than five years from January 1 of the year succeeding their date of election to the Board. All of the current Trustees exceed the required share ownership threshold.

Prior to the beginning of each calendar year, non-employee Trustees may irrevocably elect to receive all or any portion of their retainers and fees in the form of common shares. Pursuant to the Northeast Utilities Deferred Compensation Plan for Trustees, each Trustee may also irrevocably elect to defer receipt of all or a portion of cash and/or equity compensation, including RSUs issued under the Incentive Plan. Deferred funds are credited with interest at the rate set forth in Section 37-1 of the Connecticut General Statutes, which rate was 8% for all of 2011. Deferred compensation is payable either in a lump sum or in one to five annual installments in accordance with the Trustee s prior election.

A non-employee Trustee who performs additional Board-related services in the interest of Northeast Utilities or any of its subsidiaries upon the request of either the Board or the Chairman of the Board is entitled to receive additional compensation equal to $750 per half-day plus reasonable expenses. In addition, we pay travel-related expenses for spouses of Trustees who attend Board functions. The Internal Revenue Service considers payment of travel expenses for a Trustee s spouse to be imputed income to the individual Trustee. Effective January 1, 2009, we discontinued tax gross-up payments in connection with spousal travel expenses.

The table below sets forth all compensation paid to or accrued by each non-employee Trustee in 2011.

Trustee	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2)	Option Awards ($) (3)	Non-Equity Incentive Compensation ($)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings ($) (4)	All Other Compen-sation ($)	Total ($)
Richard H. Booth	118,000	105,850					223,850
John S. Clarkeson	112,500	103,350					215,850
Cotton M. Cleveland	102,000	95,850			35,588		233,438
Sanford Cloud, Jr.	112,500	95,850			2,209		210,559
John G. Graham	105,000	95,850			19,194		220,044
Elizabeth T. Kennan	183,500	95,850					279,350
Kenneth R. Leibler	128,500	95,850					224,350
Robert E. Patricelli	0	194,850					194,850
John F. Swope	99,000	103,350					202,350
Dennis R. Wraase	106,500	95,850					202,350

(1)

Represents the aggregate dollar amount of all fees earned or paid in cash, including annual retainer fees, committee and/or committee chair fees, and meeting attendance fees. Also includes the amount of cash compensation deferred at the election of the Trustee. For 2011, Ms. Cleveland deferred receipt of 75% of her board retainer and meeting fees.

(2)

Includes the grant date market value of RSU grants in 2011. Each trustee received a grant of 3,000 RSUs on January 3, 2011 at a grant date market value of $95,850, which vested on January 10, 2012. We paid one-half of the retainers for the Chair of the Audit Committee and the Chair of the Compensation Committee in cash. We paid the balance of these retainers in common shares with an acquisition date market value equal to one-half of the amount of the retainer on the payment dates. The amounts reported for Mr. Booth and Mr. Clarkeson include the grant date market value of these common shares. For Mr. Booth, the amount includes one-half the retainer paid to him on four different dates as Chair of the Audit Committee, or $10,000, which equaled the market value of 297 common shares on the grant dates. Mr. Booth deferred the receipt of these shares in accordance with the provisions of the Northeast Utilities Deferred Compensation Plan for Trustees. For Mr. Clarkeson, the amount includes one-half of the retainer paid to him on four different dates as Chair of the Compensation Committee, totaling $7,500, which equaled the market value of 291 common shares on the grant dates. The amounts reported for Mr. Patricelli and Mr. Swope include the voluntary conversion to shares of amounts earned for retainers and/or meeting fees. The amounts reported for Mr. Patricelli and Mr. Swope include the acquisition date market value of these common shares. For Mr. Patricelli, the amount includes the conversion of $99,000 to shares, which equaled the market value of 2,856 shares on five different dates, and included (i) 100% of his board retainer, or $45,000; and (ii) 100% of the amount earned for his attendance at board and committee meetings, or $54,000. For Mr. Swope, the amount includes the conversion of 100% of the retainer paid to him on four different dates as Chair of the Corporate Responsibility Committee, totaling $7,500, which equaled the market value of 223 shares. Mr. Swope deferred the receipt of these shares in accordance with the provisions of the Northeast Utilities Deferred Compensation Plan for Trustees. In addition, outstanding RSU grants accrued corresponding dividend-equivalent units that are subject to the same restrictions as the underlying RSUs. There were no outstanding option awards as of December 31, 2011. Total deferred RSU awards held by our Trustees as of December 31, 2011 were as follows:

Trustee	**RSUs and Dividend Equivalent Units Outstanding on December 31, 2011**
Richard H. Booth	27,998
John S. Clarkeson	3,096
Cotton M. Cleveland	27,998
Sanford Cloud, Jr.	13,101
John G. Graham	27,998
Elizabeth T. Kennan	28,776
Kenneth R. Leibler	3,096
Robert E. Patricelli	3,096
John F. Swope	27,998
Dennis R. Wraase	6,275

RSUs and dividend equivalent units outstanding at December 31, 2011 included 3,000 unvested RSUs granted to each Trustee on January 3, 2011, plus 96 unvested dividend equivalent units accrued on such RSUs, all of which vested on January 10, 2012. RSUs and dividend equivalent units in excess of 3,096, if any, reflect vested deferred RSUs and/or vested deferred dividend equivalent units.

All equity holdings are reported in the table captioned Common Stock Ownership of Trustees and Management appearing in Item 12 of this Annual Report on Form 10-K. Assumptions used in the calculation of this amount appear in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-

K. Forfeitures are estimated, and the compensation cost of the restricted share unit awards will be reversed if the non-employee Trustee does not remain a Trustee throughout the one-year vesting period.

(3)

We did not grant options to non-employee Trustees in 2011. We have not granted stock options since 2002.

(4)

Reflects the difference between the interest earned on amounts deferred by non-employee Trustees under the NU Deferred Compensation Plan for Trustees and interest calculated at 120% of the Internal Revenue Service prescribed applicable monthly long-term federal rate which represents a market rate of return. We do not provide pension benefits to our non-employee Trustees.

Item 12.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

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.

NU and CL&P

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, 2011, in accordance with the rules of the SEC:

Plan Category

	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,490,427	$18.78	3,582,317
Equity compensation plans not approved by security holders (d)			
Total	1,490,427	$18.78	3,582,317

(a)

Includes 47,374 common shares to be issued upon exercise of options, 959,920 common shares for distribution of restricted share units, and 483,133 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 or performance shares, which have no exercise price.

(c)

Includes 896,702 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.

NU

SECURITIES OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table provides information as to persons who are known to us to beneficially own more than five percent of the common shares of Northeast Utilities. We do not have any other class of voting securities.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Wellington Management Company, LLP 280 Congress Street Boston, Massachusetts 02210	10,137,391 (1)	5.73% (1)
BlackRock Inc. 40 East 52nd Street New York, New York 10022	15,070,628 (2)	8.51% (2)
The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, Pennsylvania 19355	11,103,386 (3)	6.27% (3)
State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	9,712,617 (4)	5.5% (4)

(1)

Based solely on a Schedule 13G/A filed with the SEC on February 14, 2012, reporting that as of December 31, 2011, Wellington Management, in its capacity as investment adviser, may be deemed to beneficially own 10,137,391 common shares, which are held of record by clients of Wellington Management. Of these shares, Wellington Management has the shared power to vote or direct the vote of 4,913,005 common shares and the shared power to dispose or direct the disposition of all of these common shares.

(2)

Based solely on a Schedule 13G/A filed with the SEC on February 10, 2012, reporting that as of December 31, 2011, BlackRock, Inc. and certain subsidiaries beneficially owned, had the sole power to vote or direct the vote of, and the sole power to dispose of or direct the disposition of, all of these common shares.

(3)

Based solely on a Schedule 13G/A filed with the SEC on February 8, 2012, reporting that as of December 31, 2011, The Vanguard Group, Inc. had the sole power to vote or direct the vote of 243,912 common shares; the sole power to dispose of or to direct the disposition of 10,859,474 common shares; and the shared power to dispose or to direct the disposition of 243,912 common shares. Vanguard Fiduciary Trust Company, a wholly-owned subsidiary of The Vanguard Group, Inc., is the beneficial owner of 243,912 common shares as investment manager of collective trust accounts and directs the voting of these shares.

(4)

Based solely on a Schedule 13G filed with the SEC on February 9, 2012, reporting that as of December 31, 2011, State Street Corporation and certain subsidiaries beneficially owned, had the shared power to vote or direct the vote of, and the shared power to dispose or to direct the disposition of, all these common shares.

COMMON SHARE OWNERSHIP OF TRUSTEES AND MANAGEMENT

The table below shows the number of our common shares beneficially owned as of February 15, 2012, by each of our Trustees and each Named Executive Officer of NU as well as the number of common shares beneficially owned by all of our Trustees and executive officers as a group. The table also includes information about options, restricted share units and deferred shares credited to the accounts of our Trustees and executive officers under certain compensation and benefit plans. We do not have any other class of voting securities. Unless otherwise indicated, the address for the shareholders listed below is c/o Northeast Utilities, 56 Prospect Street, Hartford, Connecticut 06103-2818.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (1)(2)	Percent of Class
Richard H. Booth	39,179	*
Gregory B. Butler	151,368 (3) (4) (5)	*
John S. Clarkeson	16,833	*
Cotton M. Cleveland	43,083	*
Sanford Cloud, Jr.	42,442	*
John G. Graham	39,866	*
Elizabeth T. Kennan	42,205	*
Kenneth R. Leibler	20,127	*
David R. McHale	176,404 (4) (5) (6)	*
Leon J. Olivier	161,312 (4) (5)	*
Robert E. Patricelli	55,774	*
James B. Robb	77,901 (4)	*
Charles W. Shivery	773,189 (4) (7)	*
John F. Swope	49,486	*
Dennis R. Wraase	13,275 (8)	*
All directors and Executive Officers as a Group (17 persons)	1,838,794 (9)	*

*

Less than 1% of Northeast Utilities common shares outstanding.

(1)

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

(2)

Includes common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 15, 2012, as follows: Mr. Shivery: 29,024 shares.

Also includes 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, and phantom common shares, representing employer matching contributions distributable only in cash, held by executive officers who participate in our Deferred Compensation Plan for Executives, as follows: Mr. Booth: 37,802 shares; Mr. Butler: 71,155 shares; Mr. Clarkeson: 3,000 shares; Ms. Cleveland: 34,824 shares; Mr. Cloud: 16,101 shares; Mr. Graham: 39,266 shares; Dr. Kennan: 35,794 shares; Mr. Leibler: 3,000 shares; Mr. McHale: 88,911 shares; Mr. Olivier: 76,738 shares; Mr. Patricelli: 3,000 shares; Mr. Robb: 46,331 shares; Mr. Shivery: 526,140 shares; Mr. Swope: 33,231 shares; and Mr. Wraase: 9,275 shares.

Also includes unvested performance shares reported at target payouts, plus accumulated dividend equivalents, as to which none of the individuals has voting or investment power, as follows: Mr. Butler: 31,579 shares; Mr. McHale: 40,697 shares; Mr. Olivier: 42,733 shares; Mr. Robb: 20,673 shares; and Mr. Shivery: 160,745 shares. Actual payouts of the performance shares, if any, at the conclusion of relevant performance periods will depend on the extent to which performance goals are satisfied.

(3)

Includes 44,671 common shares owned jointly by Mr. Butler and his spouse with whom he shares voting and investment power.

(4)

Includes common shares held in the 401k Plan in the employee stock ownership plan account over which the holder has sole voting and investment power (Mr. Butler: 3,512 shares; Mr. McHale: 4,237 shares; Mr. Olivier: 2,091 shares; Mr. Robb: 814 shares and Mr. Shivery: 2,231 shares).

(5)

Includes common shares held as units in the 401k Plan invested in the NU Common Shares Fund over which the holder has sole voting and investment power (Mr. Butler: 452 shares; Mr. McHale: 1,925 shares; and Mr. Olivier: 75 shares).

(6)

Includes 115 common shares held by Mr. McHale in the 401k Plan TRAESOP/PAYSOP account over which Mr. McHale has sole voting and investment power.

(7)

Includes 1,500 common shares owned jointly by Mr. Shivery and his spouse with whom he shares voting and investment power.

(8)

Includes 4,000 common shares owned jointly by Mr. Wraase and his spouse with whom he shares voting and investment power.

(9)

Includes 29,024 common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 15, 2012, and 1,356,719 unissued common shares. See note 2.

CL&P

COMMON SHARE OWNERSHIP OF DIRECTORS AND MANAGEMENT

NU owns 100 percent of the outstanding common stock of CL&P. The table below shows the number of NU s common shares beneficially owned as of February 15, 2012, by each of CL&P s Directors and each Named Executive Officer of CL&P, as well as the number of common shares beneficially owned by all of CL&P s Directors and executive officers as a group. The table also includes information about options, restricted share units and deferred shares credited to the accounts of CL&P s Directors and executive officers under certain compensation and benefit plans. No equity securities of CL&P are owned by any of the Trustees, directors or executive officers of NU or CL&P. The address for the shareholders listed below is c/o Northeast Utilities, 56 Prospect Street, Hartford, Connecticut 06103-2818.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (1)(2)(3)	Percent of Class
Charles W. Shivery, Chairman, Director of the Regulated Companies	773,189 (5) (8)	*
Leon J. Olivier, CEO, Director of the Regulated Companies	161,312 (5) (6)	*
Jean M. LaVecchia, Director of the Regulated Companies	46,554 (5)	*
David R. McHale, CFO, Director of the Regulated Companies	176,404 (5) (6) (7)	*
James A. Muntz, President and Chief Operating Officer of CL&P	77,971 (5) (6)	*
Gregory B. Butler, Senior Vice President and General Counsel, Director of the Regulated Companies	151,368 (4) (5) (6)	*
James B. Robb, Director of the Regulated Companies	77,901 (5)	*
All directors and Executive Officers as a Group (8 persons)	1,464,699 (9)	*

*

Less than 1% of Northeast Utilities 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, 2012.

(3)

Includes common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 15, 2012, as follows: Mr. Shivery: 29,024 shares.

Also includes 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, and phantom common shares, representing employer matching contributions distributable only in cash, held by executive officers who participate in our Deferred Compensation Plan for Executives, as follows; Mr. Butler: 71,155 shares; Ms. LaVecchia: 9,811 shares; Mr. McHale: 88,911 shares; Mr. Muntz: 19,109 shares; Mr. Olivier: 76,738 shares; Mr. Robb: 46,331 shares; and Mr. Shivery: 526,140 shares.

Also includes unvested performance shares reported at target payouts, plus accumulated dividend equivalents, as to which none of the individuals has voting or investment power, as follows: Mr. Butler: 31,579 shares; Ms. LaVecchia: 14,822 shares; Mr. McHale: 40,697 shares; Mr. Muntz: 20,673 shares; Mr. Olivier: 42,733 shares; Mr. Robb: 20,673 shares; and Mr. Shivery: 160,745 shares. Actual payouts of the performance shares, if any, at the conclusion of relevant performance periods will depend on the extent to which performance goals are satisfied.

(4)

Includes 44,671 shares owned jointly by Mr. Butler and his spouse with whom he shares voting and investment power.

(5)

Includes common shares held in the 401(k) Plan in the employer stock ownership plan account over which the holder has sole voting and investment power (Mr. Butler: 3,512 shares; Ms. LaVecchia: 2,820 shares; Mr. McHale: 4,237 shares; Mr. Muntz: 2,246 shares; Mr. Olivier: 2,091 shares; Mr. Robb: 813 shares; and Mr. Shivery: 2,231 shares).

(6)

Includes common shares held as units in the 401(k) Plan invested in the NU Common Shares Fund over which the holder has sole voting and investment power (Mr. Butler: 452 shares; Mr. McHale: 1,925 shares; Mr. Muntz: 1,935 shares; and Mr. Olivier: 75 shares).

(7)

Includes 115 shares held by Mr. McHale in the 401(k) Plan TRAESOP/PAYSOP account over which Mr. McHale has sole voting and investment power.

(8)

Includes 4,000 shares owned jointly by Mr. Shivery and his spouse with whom he shares voting and investment power.

(9)

Includes 29,024 common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 15, 2012 (see note 2), and 1,186,525 unissued common shares. See note 3.

Item 13.

Certain Relationships and Related Transactions, and Director Independence

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**.**

NU and 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 NU, 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 that 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 NU s Board of Trustees. The Policy generally defines a Related Party Transaction as any transaction or series of transactions in which (i) NU 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 NU's 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 or a subsidiary proposes to enter. The Corporate Governance Committee recommends to the NU 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 Corporate Governance Committee, the transaction will be subject to ratification by the NU Board of Trustees. If the NU Board of Trustees determines not to ratify the transaction, then management will make all reasonable efforts to cancel or annul such transaction.

NU

TRUSTEE INDEPENDENCE

NU has adopted Corporate Governance Guidelines incorporating independence standards for its Board of Trustees that meet the listing standards of the New York Stock Exchange. In addition, NU has adopted an additional standard under which a charitable relationship will not be considered to be a material relationship that would impair a Trustee s independence if a Trustee serves as an officer or director of a charitable organization, and our discretionary charitable contributions to the organization, in the aggregate, do not exceed the greater of: (a) $200,000; or (b) two percent of the organization s total annual charitable receipts or latest publicly available operating budget. The Trustee Independence Guidelines are available on our website at www.nu.com/investors/corporate_gov/trustee_independence.asp.

The Corporate Governance Committee of NU s Board of Trustees conducts an annual review of the independence of the members of the Board and reports its findings to the full Board. Applying the Corporate Governance Guidelines, the Committee, assisted by legal counsel and based on responses to questionnaires completed by the Trustees, reviewed and considered relationships and transactions between Northeast Utilities, its affiliates and subsidiaries, on the one hand, and each Trustee, entities affiliated with him or her, and/or any member of his or her immediate family, on the other hand. The Committee also reviewed Northeast Utilities charitable donations to organizations where the Trustees or their immediate family members serve as officers or directors. Similarly, the Committee examined relationships and transactions between each Trustee and (a) our senior management and (b) our independent auditors. The Committee determined that none of these relationships were material to the Trustees or likely to impair the independence of any of the Trustees.

The Board of Trustees separately considered that the utility operating company subsidiaries of Northeast Utilities provide electric service or natural gas service to the residences of Trustee and/or companies at which some of the Trustee were directors or executive officers. These utility services are provided in the ordinary course of business, on an arms length basis and pursuant to rates determined by the applicable public utility commission. The Board determined that relationships that exist solely due to an individual or entity purchasing electric service or natural gas service from any of the utility operating company subsidiaries of Northeast Utilities in the ordinary course of business, on an arms length basis and pursuant to rates determined by the applicable public utility commission, were not material to the Trustees or likely to impair the independence of any of the Trustees.

Based on the recommendation of the Corporate Governance Committee following its review, on February , 2012, the Board of Trustees affirmatively determined that each of the Trustees, with the exception of Mr. Shivery, NU s Chairman of the Board, President and Chief Executive Officer, satisfied the independence criteria (including the enhanced criteria with respect to members of the Audit

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Committee) set forth in the current listing standards and rules of the New York Stock Exchange and SEC and under our Corporate Governance Guidelines.

CL&P

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, 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 NU 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 NU 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 $4,366,359 and $3,697,371 for the years ended December 31, 2011 and 2010, 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, 2011 and 2010 totaled $2,956,000 and $2,713,150, 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, 2011 and 2010, as well as auditing the implementation of new accounting standards and the accounting for new contracts.

2.

Audit Related Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for audit related services rendered for the years ended December 31, 2011 and 2010 totaled $519,000 and $480,186, respectively.

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, 2011 and 2010 totaled $39,859 and $52,535, respectively. These services related primarily to the reviews of tax returns and reviewing the tax impacts of proposed transactions in 2011 and 2010.

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 for the years ended December 31, 2011 and 2010 totaled $851,500 and $451,500, respectively. All other fees in 2011 consisted primarily of consulting services related to the Company's consideration of implementing enterprise resource planning systems. All other fees in 2010 consisted primarily of mergers and acquisition advisory services. All other fees in 2011 and 2010 also included a license fee for access to an accounting research tool.

The Audit Committee of NU s Board of Trustees 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 2011, all services described above were pre-approved by the Audit Committee.

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

PART IV

Item 15.

Exhibits and Financial Statement Schedules

(a) 1. Financial Statements:

The financial statements filed as part of this Annual Report on Form 10-K are set forth under Item 8, Financial Statements and Supplementary Data. Reference is made to the index on page 74.

2. 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 24, 2012

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 24, 2012
/s/ David R. McHale David R. McHale	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2012
/s/ Jay S. Buth	Vice President - Accounting and Controller	February 24 , 2012

Jay S. Buth

/s/	Trustee	February 24, 2012
Richard H. Booth Richard H. Booth		
/s/	Trustee	February 24, 2012
John S. Clarkeson John S. Clarkeson		
/s/	Trustee	February 24, 2012
Cotton M. Cleveland Cotton M. Cleveland		
/s/	Trustee	February 24, 2012
Sanford Cloud, Jr. Sanford Cloud, Jr.		
/s/	Trustee	February 24, 2012
John G. Graham John G. Graham		
/s/	Trustee	February 24, 2012
Elizabeth T. Kennan Elizabeth T. Kennan		
/s/	Trustee	February 24, 2012
Kenneth R. Leibler Kenneth R. Leibler		
/s/	Trustee	February 24, 2012
Robert E. Patricelli Robert E. Patricelli		

/s/	Trustee	February 24, 2012
John F. Swope		
John F. Swope		
/s/	Trustee	February 24, 2012
Dennis R. Wraase		
Dennis R. Wraase		

THE CONNECTICUT LIGHT AND POWER COMPANY

SIGNATURES

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

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

By /s/ Date

Leon J. Olivier
Leon J. Olivier
Chief Executive Officer February 24, 2012
(Principal Executive Officer)

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

Signature	Title	Date
/s/ Charles W. Shivery Charles W. Shivery	Chairman and a Director	February 24, 2012
/s/ Leon J. Olivier Leon J. Olivier	Chief Executive Officer and a Director (Principal Executive Officer)	February 24, 2012
/s/ David R. McHale David R. McHale	Executive Vice President and Chief Financial Officer and a Director	February 24, 2012

	(Principal Financial Officer)	
/s/	Director	February 24, 2012
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 24, 2012
Jean M. LaVechhia Jean M. LaVecchia		
/s/	Director	February 24, 2012
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 24, 2012
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 24, 2012

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 24, 2012
Charles W. Shivery Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 24, 2012
Leon J. Olivier Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 24, 2012
Gary A. Long		

Gary A. Long	and a Director	
/s/	Executive Vice President and Chief Financial	February 24, 2012
David R. McHale David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Director	February 24, 2012
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 24, 2012
Jean M. LaVecchia Jean M. LaVecchia		
/s/	Director	February 24, 2012
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 24, 2012
Jay S. Buth Jay S. Buth		

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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 24, 2012

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 24, 2012
Charles W. Shivery Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 24, 2012
Leon J. Olivier Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 24, 2012
Peter J. Clarke		

Peter J. Clarke	and a Director	
/s/	Executive Vice President and Chief Financial	February 24, 2012
David R. McHale David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Director	February 24, 2012
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 24, 2012
Jean M. LaVecchia Jean M. LaVecchia		
/s/	Director	February 24, 2012
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 24 , 2012
Jay S. Buth Jay S. Buth		

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
BALANCE SHEETS
AS OF DECEMBER 31, 2011 AND 2010
(Thousands of Dollars)

	2011	2010
ASSETS		
Current Assets:		
Cash	$ 62	$ 268
Notes Receivable from Affiliated Companies	113,200	132,600
Accounts Receivable	2,735	2,885
Accounts Receivable from Affiliated Companies	1,749	1,163
Taxes Receivable	5,308	18,139
Prepayments and Other Current Assets	4,610	18,021
Total Current Assets	127,664	173,076
Deferred Debits and Other Assets:		
Investments in Subsidiary Companies, at Equity	4,566,865	4,323,455
Notes Receivable from Affiliated Companies	62,500	62,500
Accumulated Deferred Income Taxes	39,405	23,288
Derivative Assets	-	4,099
Other Long-Term Assets	9,979	8,179
Total Deferred Debits and Other Assets	4,678,749	4,421,521
Total Assets	$ 4,806,413	$ 4,594,597
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 256,000	$ 237,000
Long-Term Debt - Current Portion	265,296	-
Accounts Payable	266	179
Accounts Payable to Affiliated Companies	141	411
Accrued Taxes	-	3,616
Accrued Interest	8,735	8,024
Other	865	1,145
Total Current Liabilities	531,303	250,375
Deferred Credits and Other Liabilities:		
Other	9,511	6,776
Total Deferred Credits and Other Liabilities	9,511	6,776
Capitalization:		
Long-Term Debt	249,973	524,813
Equity:		
Common Shareholders' Equity:		
Common Shares	980,264	978,909

Capital Surplus, Paid in		1,797,884		1,777,592
Retained Earnings		1,651,875		1,452,777
Accumulated Other Comprehensive Loss		(70,686)		(43,370)
Treasury Stock		(346,667)		(354,732)
Common Shareholders' Equity		4,012,670		3,811,176
Noncontrolling Interests		2,956		1,457
Total Equity		4,015,626		3,812,633
Total Capitalization		4,265,599		4,337,446
Total Liabilities and Capitalization	$	4,806,413	$	4,594,597

See the *Combined Notes to Consolidated Financial Statements* in this Annual Report on Form 10-K for a description of material obligations, guarantees and other significant accounting matters related to NU parent.

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009
(Thousands of Dollars, Except Share Information)

	2011	2010	2009
Operating Revenues	$ -	$ -	$ -
Operating Expenses:			
Other	19,075	21,081	3,251
Operating Loss	(19,075)	(21,081)	(3,251)
Interest Expense	26,767	12,058	29,678
Other Income, Net:			
Equity in Earnings of Subsidiaries	422,408	396,333	346,137
Other, Net	4,247	4,536	6,511
Other Income, Net	426,655	400,869	352,648
Income Before Income Tax Benefit	380,813	367,730	319,719
Income Tax Benefit	(14,142)	(20,276)	(10,314)
Net Income	394,955	388,006	330,033
Net Income Attributable to Noncontrolling Interest	262	57	-
Net Income Attributable to Controlling Interest	$ 394,693	$ 387,949	$ 330,033
Basic Earnings per Common Share	$ 2.22	$ 2.20	$ 1.91
Diluted Earnings per Common Share	$ 2.22	$ 2.19	$ 1.91
Weighted Average Common Shares Outstanding:			
Basic	177,410,167	176,636,086	172,567,928
Diluted	177,804,568	176,885,387	172,717,246

See the *Combined Notes to Consolidated Financial Statements* in this Annual Report on Form 10-K for a description of material obligations, guarantees and other significant accounting matters related to NU parent.

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009
(Thousands of Dollars)

	2011	2010	2009
Operating Activities:			
Net Income	$ 394,955	$ 388,006	$ 330,033
Adjustments to Reconcile Net Income to Net Cash			
Flows Provided by Operating Activities:			
Equity in Earnings of Subsidiaries	(422,408)	(396,333)	(346,137)
Cash Dividends Received from Subsidiaries	389,292	309,669	207,877
Deferred Income Taxes	(15,934)	8,398	(6,658)
Other	33,238	23,675	15,525
Changes in Current Assets and Liabilities:			
Receivables, Including Affiliate Receivables	(436)	791	(861)
Accounts Payable, Including Affiliate Payables	(183)	590	(35,522)
Taxes Receivable/Accrued	11,537	(28,394)	5,591
Other Current Assets and Liabilities	484	(12,656)	2,369
Net Cash Flows Provided by Operating Activities	390,545	293,746	172,217
Investing Activities:			
Capital Contributions to Subsidiaries	(233,349)	(313,560)	(243,688)
Return of Investment in Subsidiaries	-	5,000	-
Decrease in NU Money Pool Lending	400	83,300	128,700
Decrease/(Increase) in Notes Receivable from Affiliated Companies	19,000	(29,687)	(72,709)
Other Investing Activities	(2,585)	1,703	2,283
Net Cash Flows Used in Investing Activities	(216,534)	(253,244)	(185,414)
Financing Activities:			
Issuance of Common Shares	-	-	383,295
Cash Dividends on Common Shares	(194,555)	(180,542)	(162,381)
Increase/(Decrease) in Short-Term Debt	19,000	136,687	(203,206)
Financing Fees	-	-	(12,457)
Other Financing Activities	1,338	2,399	7,874
Net Cash Flows (Used in)/Provided by Financing Activities	(174,217)	(41,456)	13,125
Net Decrease in Cash	(206)	(954)	(72)
Cash - Beginning of Year	268	1,222	1,294
Cash - End of Year	$ 62	$ 268	$ 1,222

Supplemental Cash Flow Information:

Cash Paid/(Received) During the Year for:						
Interest	$	24,951	$	22,886	$	26,744
Income Taxes	$	(10,833)	$	1,291	$	(12,848)

See the *Combined Notes to Consolidated Financial Statements* in this Annual Report on Form 10-K for a description of material obligations, guarantees and other significant accounting matters related to NU parent.

SCHEDULE II
NORTHEAST UTILITIES AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description:	Balance as of Beginning of Year	Charged to Costs and Expenses	Charged to Other Accounts - Describe (a)	Deductions - Describe (b)	Balance as of End of Year
NU:					
Reserves Deducted from Assets - Reserves for Uncollectible Accounts:					
2011	$ 39,797	$ 16,420	$ 8,664	$ 30,020	$ 34,861
2010	55,300	31,352	10,714	57,569	39,797
2009	43,275	53,947	24,136	66,058	55,300
CL&P:					
Reserves Deducted from Assets - Reserves for Uncollectible Accounts:					
2011	$ 17,174	$ 3,215	$ 5,659	$ 11,209	$ 14,839
2010	26,057	7,484	9,919	26,286	17,174
2009	23,956	15,276	20,115	33,290	26,057
PSNH:					
Reserves Deducted from Assets - Reserves for Uncollectible Accounts:					
2011	$ 6,824	$ 7,035	$ 1,334	$ 8,003	$ 7,190
2010	5,086	8,858	1,017	8,137	6,824
2009	4,165	10,084	652	9,815	5,086
WMECO:					
Reserves Deducted from Assets - Reserves for Uncollectible Accounts:					
2011	$ 5,975	$ 3,133	$ 1,038	$ 5,555	$ 4,591
2010	7,217	9,747	243	11,232	5,975

2009	6,571	7,590	103	7,047	7,217

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

(b) Amounts written off, net of recoveries. The PURA issued an order allowing CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. As a result of the January 2011 DPU rate case decision, WMECO is allowed to recover amounts associated with uncollectible hardship receivables in rates. As of December 31, 2011, CL&P, WMECO and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $68.6 million, $5.4 million and $6.8 million, respectively. As of December 31, 2010, CL&P, WMECO and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $65 million, $6.9 million and $7.5 million, respectively. As of December 31, 2009, CL&P, WMECO and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $54.5 million, $9.1 million and $8.6 million, respectively.

EXHIBIT INDEX

Each document described below is incorporated by reference by the registrant(s) listed to the files identified, unless designated with a (*), which exhibits are filed herewith. Management contracts and compensation plans or arrangements are designated with a (+).

Exhibit

Number

Description

2.

Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession

(A)

Northeast Utilities

2.1

Agreement and Plan of Merger By and Among Northeast Utilities, NU Holding Energy 1 LLC, NU Holding Energy 2 LLC and NSTAR dated as of October 16, 2010 (Exhibit 2.1 Current Report on Form 8-K filed October 18, 2010, File No. 001-05324)

2.1.1

Amendment 1 to Agreement and Plan of Merger By and Among Northeast Utilities, NU Holding Energy 1 LLC, NU Holding Energy 2 LLC and NSTAR dated as of November 1, 2010 (Exhibit 2.1.1, 2010 NU Form 10-K filed February 25, 2011, File No. 001-05324)

2.1.2

Amendment 2 to Agreement and Plan of Merger By and Among Northeast Utilities, NU Holding Energy 1 LLC, NU Holding Energy 2 LLC and NSTAR dated as of December 16, 2010 (Exhibit 2.1.2, 2010 NU Form 10-K filed February 25, 2011, File No. 001-05324)

3.

Articles of Incorporation and By-Laws

(A)

Northeast Utilities

3.1

Declaration of Trust of NU, as amended through May 10, 2005 (Exhibit A.1, NU Form U-1 filed June 23, 2005, File No. 70-10315)

(B)

The Connecticut Light and Power Company

3.1

Certificate of Incorporation of CL&P, restated to March 22, 1994 (Exhibit 3.2.1, 1993 CL&P Form 10-K, File No. 000-00404)

3.1.1

Certificate of Amendment to Certificate of Incorporation of CL&P, dated December 26, 1996 (Exhibit 3.2.2, 1996 CL&P Form 10-K filed March 25, 1997, File No. 001-11419)

3.1.2

Certificate of Amendment to Certificate of Incorporation of CL&P, dated April 27, 1998 (Exhibit 3.2.3, 1998 CL&P Form 10-K filed March 23, 1999, File No. 000-00404)

3.1.3

Amended and Restated Certificate of Incorporation of CL&P, dated effective January 3, 2012 (Exhibit 3(i), CL&P Current Report on Form 8-K filed January 9, 2012, File No. 000-00404)

3.2

By-laws of CL&P, as amended to January 1, 1997 (Exhibit 3.2.3, 1996 CL&P Form 10-K filed March 25, 1997, File No. 001-11419)

(C)

Public Service Company of New Hampshire

3.1

Articles of Incorporation, as amended to May 16, 1991 (Exhibit 3.3.1, 1993 PSNH Form 10-K filed on March 25, 1994, File No. 001-06392)

3.2

By-laws of PSNH, as in effect June 27, 2008 (Exhibit 3, PSNH Form 10-Q for the Quarter Ended June 30, 2008 filed August 7, 2008, File No. 001-06392)

(D)

Western Massachusetts Electric Company

3.1

Articles of Organization of WMECO, restated to February 23, 1995 (Exhibit 3.4.1, 1994 WMECO Form 10-K filed on March 27, 1995, File No. 001-07624)

3.2

By-laws of WMECO, as amended to April 1, 1999 (Exhibit 3.1, WMECO Form 10-Q for the Quarter Ended June 30, 1999 filed August 13, 1999, File No. 000-07624)

§

By-laws of WMECO, as further amended to May 1, 2000 (Exhibit 3.1, WMECO Form 10-Q for the Quarter Ended June 30, 2000 filed August 11, 2000, File No. 000-07624)

4.

Instruments defining the rights of security holders, including indentures

(A)

Northeast Utilities

4.1

Indenture between NU and The Bank of New York as Trustee dated as of April 1, 2002 (Exhibit A-3, NU 35-CERT filed April 16, 2002, File No. 070-09535)

4.1.1

First Supplemental Indenture between NU and The Bank of New York as Trustee dated as of April 1, 2002, relating to $263 million of Senior Notes, Series A, due 2012 (Exhibit A-4, NU 35-CERT filed April 16, 2002, File No. 070-09535)

4.1.2

Third Supplemental Indenture between NU and The Bank of New York Trust Company N.A., as Trustee, dated as of June 1, 2008, relating to $250 million of Senior Notes, Series C, due 2013, (Exhibit 4.1, NU Current Report on Form 8-K filed June 10, 2008, File No. 001-05324)

4.2

Credit Agreement between NU, the Banks Named Therein, Union Bank, N.A. as Administrative Agent, and Barclays Bank, PLC, Citibank, N.A., JPMorgan Chase Bank, N.A. and Union Bank, N.A., as Fronting Banks dated September 24, 2010 (Exhibit 10, NU Form 10-Q for the Quarter Ended September 30, 2010, filed November 8, 2010, File No. 001-05324)

(B)

The Connecticut Light and Power Company

4.1

Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, Trustee, dated as of May 1, 1921 (Composite including all twenty-four amendments to May 1, 1967) (Exhibit 4.1.1, 1989 NU Form 10-K, File No. 001-05324)

4.1.1

Series D Supplemental Indentures to the Composite May 1, 1921 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, dated as of October 1, 1994 (Exhibit 4.2.16, 1994 CL&P Form 10-K filed on March 27, 1995, File No. 001-11419)

4.1.2

Series A Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee, dated as of September 1, 2004 (Exhibit 99.2, CL&P Current Report on Form 8-K filed September 22, 2004, File No. 000-00404)

4.1.3

Series B Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of September 1, 2004 (Exhibit 99.5, CL&P Current Report on Form 8-K filed September 22, 2004, File No. 000-00404)

4.2

Composite Indenture of Mortgage and Deed of Trust between CL&P and Deutsche Bank Trust Company Americas f/k/a Bankers Trust Company, dated as of May 1, 1921, as amended and supplemented by seventy-three supplemental mortgages to and including Supplemental Mortgage dated as of April 1, 2005 (Exhibit 99.5, CL&P Current Report on Form 8-K filed April 13, 2005, File No. 000-00404)

4.2.1

Supplemental Indenture (2005 Series A Bonds and 2005 Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of April 1, 2005 (Exhibit 99.2, CL&P Current Report on Form 8-K filed April 13, 2005, File No. 000-00404)

4.2.2

Supplemental Indenture (2006 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of June 1, 2006 (Exhibit 99.2, CL&P Current Report on Form 8-K filed June 7, 2006, File No. 000-00404)

4.2.3

Supplemental Indenture (2007 Series A Bonds and 2007 Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of March 1, 2007 (Exhibit 99.2, CL&P Current Report on Form 8-K filed March 29, 2007, File No. 000-00404)

4.2.4

Supplemental Indenture (2007 Series C Bonds and 2007 Series D Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of September 1, 2007 (Exhibit 4, CL&P Current Report on Form 8-K filed September 19, 2007, File No. 000-00404)

4.2.5

Supplemental Indenture (2008 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of May 1, 2008 (Exhibit 4, CL&P Current Report on Form 8-K filed May 29, 2008, File No. 000-00404)

4.2.6

Supplemental Indenture (2009 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of February 1, 2009 (Exhibit 4, CL&P Current Report on Form 8-K filed February 19, 2009, File No. 000-00404)

4.2.7

Supplemental Indenture (2011 Series A and Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of October 1, 2011 (Exhibit 4.1, CL&P Current Report on Form 8-K filed October 28, 2011, File No. 000-00404)

4.3

Financing Agreement between The Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds, 1986 Series) dated as of December 1, 1986 (Exhibit C.1.47, 1986 NU Form U5S, File No. 030-00246)

4.4

Financing Agreement between The Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Revenue Bonds, 1988 Series) dated as of October 1, 1988 (Exhibit C.1.55, 1988 NU Form U5S, File No. 030-00246)

4.5

Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire, CL&P and BayBank, the Trustee (Pollution Control Refunding Revenue Bonds, 1992 Series A) dated as of December 1, 1992 (Exhibit C 2.33, 1992 NU Form U5S, File No. 030-00246)

4.6

Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Revenue Refunding Bonds 1993B Series) dated as of September 1, 1993 (Exhibit 4.2.22, 1993 CL&P Form 10- K filed March 25, 1994, File No. 000-00404)

4.7

Amended and Restated Loan Agreement between Connecticut Development Authority and CL&P dated as of May 1, 1996 and Amended and Restated as of January 1, 1997 (Pollution Control Revenue Bond - 1996A Series) (Exhibit 4.2.24, 1996 CL&P Form 10-K filed March 25, 1997, File No. 001-11419)

4.7.1

First Amendment to Amended and Restated Loan Agreement, between the Connecticut Development Authority and CL&P dated as of October 1, 2008 (Pollution Control Revenue Bond-1996A Series) (Exhibit 10.1, CL&P Form 10-Q for the Quarter Ended September 30, 2008, filed November 10, 2008, File No. 000-00404)

4.8

Amended and Restated Indenture of Trust between Connecticut Development Authority and Fleet National Bank, the Trustee dated as of May 1, 1996 and Amended and Restated as of January 1, 1997 (Pollution Control Revenue Bond-1996A Series) (Exhibit 4.2.24.1, 1996 CL&P Form 10-K, filed March 25, 1997, File No. 001-11419)

4.8.1

First Amendment to Amended and Restated Indenture of Trust between Connecticut Development Authority and U.S. Bank National Association, as Trustee dated as of October 1, 2008 (Exhibit 10.2 CL&P Form 10-Q for the Quarter Ended September 30, 2008, filed November 10, 2008, File No. 000-00404)

4.9

Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Revenue Refunding Bonds 2011A Series) dated as of October 1, 2011 (Exhibit 1.1, CL&P Current Report on Form 8-K filed October 28, 2011, File No. 000-00404)

4.10

Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Revenue Refunding Bonds 2011B Series) dated as of October 1, 2011 (Exhibit 1.2, CL&P Current Report on Form 8-K filed October 28, 2011, File No. 000-00404)

4.11

Credit Agreement between CL&P, WMECO, Yankee Gas and PSNH, the Banks Named Therein, and Citicorp N.A., as Administrative Agent dated September 24, 2010 (Exhibit 10, CL&P Form 10-Q for the Quarter Ended September 30, 2010 filed November 8, 2010, File No. 000-00404)

(C)

Public Service Company of New Hampshire

4.1

First Mortgage Indenture between PSNH and First Fidelity Bank, National Association, New Jersey, now First Union National Bank, Trustee, dated as of August 15, 1978 (Composite including all amendments effective June 1, 2011) (included as Exhibit C to the Eighteen Supplemental Indenture filed as Exhibit 4.1 to PSNH Current Report on Form 8-K filed on June 2, 2011, File No. 001-06392)

4.1.1

Twelfth Supplemental Indenture between PSNH and First Union National Bank dated as of December 1, 2001 (Exhibit 4.3.1.2, 2001 PSNH Form 10-K filed March 22, 2002, File No. 001-06392)

4.1.2

Thirteenth Supplemental Indenture between PSNH and Wachovia Bank, National Association, successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee dated as of July 1, 2004 (Exhibit 99.2, PSNH Current Report on Form 8-K filed October 5, 2004, File No. 001-06392)

4.1.3

Fourteenth Supplemental Indenture between PSNH and Wachovia Bank, National Association successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee dated as of October 1, 2005 (Exhibit 99.2, PSNH Current Report on Form 8-K filed October 6, 2005, File No. 001-06392)

4.1.4

Fifteenth Supplemental Indenture between PSNH and Wachovia Bank, National Association successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee dated as of September 1, 2007 (Exhibit 4.1, PSNH Current Report on Form 8-K filed September 25, 2007, File No. 001-06392)

4.1.5

Sixteenth Supplemental Indenture between PSNH and U.S. Bank National Association, Trustee, dated as of May 1, 2008 (Exhibit 4.1 to PSNH Current Report on Form 8-K filed May 29, 2008 (File No.001-06392)

4.1.6

Seventeenth Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as of December 1, 2009 (Exhibit 4.1, PSNH Current Report on Form 8-K filed December 15, 2009 (File No. 001-06392)

4.17

Eighteenth Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as May 1, 2011 (Exhibit 4.1, PSNH Current Report on Form 8-K filed June 2, 2011 (File No. 001-06392)

4.18

Nineteenth Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as September 1, 2011 (Exhibit 4.1, PSNH Current Report on Form 8-K filed September 16, 2011 (File No. 001-06392)

4.2

Series A Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001 (Exhibit 4.3.4, 2001 NU Form 10-K filed March 22, 2002, File No. 001-05324)

4.3

Series B Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001 (Exhibit 4.3.5, 2001 NU Form 10-K filed March 22, 2002, File No. 001-05324)

4.4

Series C Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001 (Exhibit 4.3.6, 2001 NU Form 10-K filed March 22, 2002, File No. 001-05324)

4.5

Credit Agreement between CL&P, WMECO, Yankee Gas and PSNH, the Banks Named Therein, and Citicorp, N.A., as Administrative Agent dated September 24, 2010 (Exhibit 10, PSNH Form 10-Q for the Quarter Ended September 30, 2010 filed November 8, 2010, File No. 001-06392)

(D)

Western Massachusetts Electric Company

4.1

Loan Agreement between Connecticut Development Authority and WMECO, (Pollution Control Revenue Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993 (Exhibit 4.4.13, 1993 WMECO Form 10-K filed March 25,1994, File No. 000-07624)

4.2

Indenture between WMECO and The Bank of New York, as Trustee, dated as of September 1, 2003 (Exhibit 99.2, WMECO Current Report on Form 8-K filed October 8, 2003, File No. 000-07624)

4.2.1

First Supplemental Indenture between WMECO and The Bank of New York, as Trustee, dated as of September 1, 2003 (Exhibit 99.3, WMECO Current Report on Form 8-K filed October 8, 2003, File No. 000-07624)

4.2.2

Second Supplemental Indenture between WMECO and The Bank of New York, as Trustee dated as of September 1, 2004 (Exhibit 4.1, WMECO Current Report on Form 8-K filed September 27, 2004, File No. 000-07624)

4.2.3

Third Supplemental Indenture between WMECO and The Bank of New York Trust, as Trustee, dated as of August 1, 2005 (Exhibit 4.1, WMECO Current Report on Form 8-K filed August 12, 2005, File No. 000-07624)

4.2.4

Fourth Supplemental Indenture between WMECO and The Bank of New York Trust, as Trustee, dated as of August 1, 2007 (Exhibit 4.1, WMECO Current Report on Form 8-K filed August 20, 2007, File No. 000-07624)

4.2.5

Fifth Supplemental Indenture between WMECO and The Bank of New York Trust Company, N.A., as Trustee, dated as of March 1, 2010 (Exhibit 4.1, WMECO Current Report on Form 8-K filed March 10, 2010, File No. 000-07624)

4.2.6

Sixth Supplemental Indenture between WMECO and The Bank of New York Trust Company, N.A., as Trustee, dated as of September 15, 2011 (Exhibit 4.1, WMECO Current Report on Form 8-K filed September 19, 2011, File No. 000-07624)

4.3

Credit Agreement between CL&P, WMECO, Yankee Gas and PSNH, the Banks Named Therein, and Citicorp, N.A., as Administrative Agent dated September 24, 2010 (Exhibit 10, WMECO Form 10-Q for the Quarter Ended September 30, 2010 filed November 8, 2010, File No. 000-07624)

10.

Material Contracts

(A)

NU

10.1

Lease between The Rocky River Realty Company and Northeast Utilities Service Company dated as of April 14, 1992 with respect to the Berlin, Connecticut headquarters (Exhibit 10.29.1, 1992 NU Form 10-K, File No. 001-05324)

10.2

Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and the Connecticut National Bank, as Trustee, dated July 1, 1989 (Exhibit 4.7, Yankee Energy System, Inc. Form 10-K for the year ended September 30, 1990, File No. 001-10721)

10.2.1

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

10.2.2

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

10.2.3

Sixth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) dated January 1, 2004 (Exhibit 10.5.6, 2004 NU Form 10-K filed March 17, 2005, File No. 001-05324)

10.2.4

Seventh Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) dated November 1, 2004 (Exhibit 10.5.7, 2004 NU Form 10-K filed March 17, 2005, File No. 001-05324)

10.2.5

Eighth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly the Connecticut National Bank) dated July 1, 2005 (Exhibit 10.5.8, NU Form 10-Q for the Quarter Ended June 30, 2005 filed August 8, 2005, File No. 001-05324)

10.2.6

Ninth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York Mellon Trust Company, N.A., successor as Trustee to The Bank of New York, as successor to Fleet National Bank (formerly known as The Connecticut National Bank) dated as of October 1, 2008 (Exhibit 10-1, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

10.2.7

Tenth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York Mellon Trust Company, N.A., successor as Trustee to The Bank of New York, as successor to Fleet National Bank (formerly known as The Connecticut National Bank), dated as of April 1, 2010 (Exhibit 10, NU Form 10-Q for the Quarter Ended March 31, 2010 filed May 7, 2010, File No. 001-05324)

* +10.3

Northeast Utilities Board of Trustees' Compensation Arrangement Summary

+10.4

Amended and Restated Northeast Utilities Deferred Compensation Plan for Trustees, effective January 1, 2009 (Exhibit 10.6, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

10.5

Limited Liability Company Agreement of Northern Pass Transmission LLC dated as of April 6, 2010 (Exhibit 10.5, 2010 NU Form 10-K filed February 25, 2011, File No. 001-05324)

10.5.1

Amendment No. 1 to Limited Liability Company Agreement of Northern Pass Transmission LLC, dated as of May 14, 2010 (Exhibit 10.5.1, 2010 NU Form 10-K filed February 25, 2011, File No. 001-05324)

10.5.2

Amendment No. 2 to Limited Liability Company Agreement of Northern Pass Transmission LLC, dated as of November 18, 2010 (Exhibit 10.5.2, 2010 NU Form 10-K filed February 25, 2011, File No. 001-05324)

10.6

Transmission Service Agreement by and between Northern Pass Transmission LLC, as Owner and H.Q. Hydro Renewable Energy, Inc., as Purchaser dated October 4, 2010 (Exhibit 10.6, 2010 NU Form 10-K filed February 25, 2011, File No. 001-05324)

(B)

NU, CL&P, PSNH and WMECO

10.1

Form of Service Contract between each of NU, CL&P and WMECO and Northeast Utilities Service Company (NUSCO) dated as of July 1, 1966 (Exhibit 10.20, 1993 NU Form 10-K filed March 25, 1994, File No. 001-05324)

10.1.1

Form of Renewal of Service Contract (Exhibit 10.2, 2006 NU Form 10-K filed March 1, 2007, File No. 001-05324)

10.2

Agreements among New England Utilities with respect to the Hydro-Quebec interconnection projects (Exhibits 10(u) and 10(v); 10(w), 10(x), and 10(y), 1990 and 1988, respectively, Form 10-K of New England Electric System, File No. 001-03446)

10.3

Transmission Operating Agreement between the Initial Participating Transmission Owners, Additional Participating Transmission Owners and ISO New England, Inc. dated as of February 1, 2005 (Exhibit 10.29, 2004 NU Form 10-K filed March 17, 2005, File No. 001-05324)

10.3.1

Rate Design and Funds Disbursement Agreement among the Initial Participating Transmission Owners, Additional Participating Transmission Owners and ISO New England, Inc., effective June 30, 2006 (Exhibit 10.22.1, 2006 NU Form 10-K filed March 1, 2007, File No. 001-05324)

10.4

Northeast Utilities Service Company Transmission and Ancillary Service Wholesale Revenue Allocation Methodology among The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, Holyoke Water Power Company and Holyoke Power and Electric Company Trustee dated as of January 1, 2008 (Exhibit 10.1, NU Form 10-Q for the Quarter Ended March 31, 2008 filed May 9, 2008, File No. 001-05324)

+10.5

Amended and Restated Employment Agreement with Charles W. Shivery, effective January 1, 2009 (Exhibit 10.6, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.6

Amended and Restated Employment Agreement with Gregory B. Butler, effective January 1, 2009 (Exhibit 10.7, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.7

Amended and Restated Employment Agreement with David R. McHale, effective January 1, 2009 (Exhibit 10.8, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.8

Amended and Restated Memorandum Agreement between Northeast Utilities and Leon J. Olivier effective January 1, 2009 (Exhibit 10.9, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.9

Amended and Restated Incentive Plan Effective January 1, 2009 (Exhibit 10.3, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.10

Amended and Restated Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Company effective January 1, 2009 (Exhibit 10.5, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.11

Trust under Supplemental Executive Retirement Plan dated May 2, 1994 (Exhibit 10.33, 2002 NU Form 10-K filed March 21, 2003, File No. 001-05324)

+10.11.1

First Amendment to Trust Under Supplemental Executive Retirement Plan, effective as of December 10, 2002 (Exhibit 10 (B) 10.19.1, 2003 NU Form 10-K filed March 12, 2004, File No. 001-05324)

+10.11.2

Second Amendment to Trust Under Supplemental Executive Retirement Plan , effective as of November 12, 2008 (Exhibit 10.12.2, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.12

Special Severance Program for Officers of NU System Companies as of January 1, 2009, (Exhibit 10.2, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.13

Amended and Restated Northeast Utilities Deferred Compensation Plan for Executives effective as of January 1, 2009 (Exhibit 10.4 NU Form 10-Q for Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.14

Agreement with James B. Robb effective October 15, 2009 (Exhibit 10.14 2009 NU Form 10-K filed February 26, 2010, File No. 001-05324)

+10.15

Northeast Utilities Retention Agreement (Exhibit 10.1, NU Registration Statement on Form S-4, filed November 22, 2010, File No. 333-170754)

10.16

Northeast Utilities System's Second Amended and Restated Tax Allocation Agreement dated as of September 21, 2005 (Exhibit D.4 to Amendment No. 1 to U5S Annual Report for the year ended December 31, 2004, filed September 30, 2005, File No. 001-05324)

*+10.17

Amendment and Restatement of Agreement between Northeast Utilities and James A. Muntz effective January 1, 2009

(C)

NU and CL&P

10.1

CL&P Agreement Re: Connecticut NEEWS Projects by and between CL&P and The United Illuminating Company dated July 14, 2010 (Exhibit 10, CL&P Form 10-Q for the Quarter Ended June 30, 2010 filed on August 6, 2010, File No. 000-00404)

(D)

NU and PSNH

10.1

PSNH Purchase and Sale Agreement with PSNH Funding LLC dated as of April 25, 2001 (Exhibit 10.57, 2001 NU Form 10-K filed March 22, 2002, File No. 001-05324)

10.2

PSNH Servicing Agreement with PSNH Funding LLC dated as of April 25, 2001 (Exhibit 10.58, 2001 NU Form 10-K filed March 22, 2002, File No. 001-05324)

(E)

NU and WMECO

10.1

Lease and Agreement by and between WMECO and Bank of New England, N.A., with BNE Realty Leasing Corporation of North Carolina dated as of December 15, 1988, (Exhibit 10.63, 1988 NU Form 10-K, File No. 001-05324)

10.2

WMECO Transition Property Purchase and Sale Agreement between WMECO Funding LLC and WMECO, dated as of May 17, 2001 (Exhibit 10.61, 2001 NU Form 10-K filed March 22, 2002, File No. 000-05324)

10.3

WMECO Transition Property Servicing Agreement between WMECO Funding LLC and WMECO, dated as of May 17, 2001 (Exhibit 10.62, 2001 NU Form 10-K filed March 22, 2002, File No. 000-05324)

*12.

Ratio of Earnings to Fixed Charges

(A)

Northeast Utilities

(B)

The Connecticut Light and Power Company

(C)

Public Service Company of New Hampshire

(D)

Western Massachusetts Electric Company

*21.

Subsidiaries of the Registrant

*23.

Consent of Independent Registered Public Accounting Firm

*31.

Rule 13a 14(a)/15 d 14(a) Certifications

(A)

Northeast Utilities

31

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of NU required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of NU required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

(B)

The Connecticut Light and Power Company

31

Certification of Leon J. Olivier, Chief Executive Officer of CL&P required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of CL&P required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

(C)

Public Service Company of New Hampshire

31

Certification of Leon J. Olivier, Chief Executive Officer of PSNH required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of PSNH required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

(D)

Western Massachusetts Electric Company

31

Certification of Leon J. Olivier, Chief Executive Officer of WMECO required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of WMECO required by Rule 13a 14(a)/15d 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

*32

18 U.S.C. Section 1350 Certifications

(A)

Northeast Utilities

32

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities and David R. McHale, Executive Vice President and Chief Financial Officer of Northeast Utilities, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

(B)

The Connecticut Light and Power Company

32

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company and David R. McHale, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

(C)

Public Service Company of New Hampshire

32

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire and David R. McHale, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

(D)

Western Massachusetts Electric Company

32

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company and David R. McHale, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2011

*101.INS

XBRL Instance Document

*101.SCH

XBRL Taxonomy Extension Schema

*101.CAL

XBRL Taxonomy Extension Calculation

*101.DEF

XBRL Taxonomy Extension Definition

*101.LAB

XBRL Taxonomy Extension Labels

*101.PRE

XBRL Taxonomy Extension Presentation