NSTAR ELECTRIC CO
Form 10-K
February 28, 2013

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, 2012
	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		06-0303850

	THE CONNECTICUT LIGHT AND POWER COMPANY (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	
1-02301	**NSTAR ELECTRIC COMPANY** (a Massachusetts corporation) 800 Boylston Street Boston, Massachusetts 02199 Telephone: (617) 424-2000	04-1278810
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	02-0181050
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

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

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

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

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

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

NSTAR Electric Company Preferred Stock, par value $100.00 per share, issuable in series, of which the following series are outstanding:

4.25%	Series
4.78%	Series

NSTAR Electric Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and each is 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
NSTAR Electric 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
NSTAR Electric 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, 2012) was $12,177,646,948 based on a closing sales price of $38.81 per share for the 313,776,010 common shares outstanding on June 30, 2012.

Northeast Utilities, directly or indirectly, holds all of the 6,035,205 shares, 100 shares, 301 shares, and 434,653 shares of the outstanding common stock of The Connecticut Light and Power Company, NSTAR Electric 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, 2013
Northeast Utilities Common shares, $5.00 par value	314,338,271 shares
The Connecticut Light and Power Company Common stock, $10.00 par value	6,035,205 shares
NSTAR Electric Company Common Stock, $1.00 par value	100 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:

CL&P	The Connecticut Light and Power Company
CYAPC	Connecticut Yankee Atomic Power Company
Hopkinton	Hopkinton LNG Corp., a wholly owned subsidiary of NSTAR LLC
HWP	HWP Company, formerly the Holyoke Water Power Company
MYAPC	Maine Yankee Atomic Power Company
NGS	Northeast Generation Services Company and subsidiaries
NPT	Northern Pass Transmission LLC
NSTAR	Parent Company of NSTAR Electric, NSTAR Gas and other subsidiaries (prior to the merger with NU); also the term used for NSTAR LLC and its subsidiaries
NSTAR Electric	NSTAR Electric Company
NSTAR Electric & Gas	NSTAR Electric & Gas Corporation, a Northeast Utilities service company
NSTAR Gas	NSTAR Gas Company
NSTAR LLC	Post-merger parent company of NSTAR Electric, NSTAR Gas and other subsidiaries, and successor to NSTAR
NU Enterprises	NU Enterprises, Inc., the parent company of Select Energy, NGS, NGS Mechanical, Select Energy Contracting, Inc. and E.S. Boulos Company
NU or the Company	Northeast Utilities and subsidiaries
NU parent and other companies	NU parent and other companies is comprised of NU parent, NSTAR LLC, NSTAR Electric & Gas, NUSCO and other subsidiaries, including NU Enterprises, NSTAR Communications, Inc., HWP, RRR (a real estate subsidiary), the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company and Yankee Energy Financial Services Company), and the consolidated operations of CYAPC and YAEC
NUSCO	Northeast Utilities Service Company
NUTV	NU Transmission Ventures, Inc., the parent company of NPT and Renewable Properties, Inc.
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's Regulated companies, comprised of the electric distribution and transmission businesses of CL&P, NSTAR Electric, PSNH, and WMECO, the natural gas distribution businesses of Yankee Gas and NSTAR Gas, the generation activities of PSNH and WMECO, and NPT
RRR	The Rocky River Realty Company

Select Energy	Select Energy, Inc.
WMECO	Western Massachusetts Electric Company
YAEC	Yankee Atomic Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Companies	CYAPC, YAEC and MYAPC
Yankee Gas	Yankee Gas Services Company
REGULATORS:	
DEEP	Connecticut Department of Energy and Environmental Protection
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DPU	Massachusetts Department of Public Utilities
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ISO-NE	ISO New England, Inc., the New England Independent System Operator
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission
PURA	Connecticut Public Utilities Regulatory Authority
SEC	U.S. Securities and Exchange Commission
SJC	Supreme Judicial Court of Massachusetts
OTHER:	
2010 Healthcare Act	Patient Protection and Affordable Care Act
AFUDC	Allowance For Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income/(Loss)
ARO	Asset Retirement Obligation
C&LM	Conservation and Load Management
CfD	Contract for Differences
Clean Air Project	The construction of a wet flue gas desulphurization system, known as "scrubber technology," to reduce mercury emissions of the Merrimack coal-fired generation station in Bow, New Hampshire
CO_2	Carbon dioxide
CPSL	Capital Projects Scheduling List
CTA	Competitive Transition Assessment
CWIP	Construction work in progress
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service

ESOP	Employee Stock Ownership Plan
ESPP	Employee Share 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
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Gigawatt-Hours
HG&E	Holyoke Gas and Electric, a municipal department of the City 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	Hydro Renewable Energy, Inc., a wholly owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
kV	Kilovolt
kW	Kilowatt (equal to one thousand watts)
kWh	Kilowatt-Hours (the basic unit of electricity energy equal to one kilowatt of power supplied for one hour)
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.
MMBtu	One million British thermal units
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
NEEWS	New England East-West Solution
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NO_x	Nitrogen oxide
NU Money Pool	Northeast Utilities Money Pool
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
NU 2011 Form 10-K	The Northeast Utilities and Subsidiaries 2011 combined Annual Report on Form 10-K as filed with the SEC
NSTAR 2011 Form 10-K	NSTAR 2011 Annual Report on Form 10-K as filed with the SEC
NSTAR Electric 2011 Form 10-K	NSTAR Electric 2011 Annual Report on Form 10-K as filed with the SEC

PAM	Pension and PBOP Rate Adjustment Mechanism
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
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
ROE	Return on Equity
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
SIP	Simplified Incentive Plan
SO_2	Sulfur dioxide
SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company

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

2012 FORM 10-K ANNUAL REPORT

TABLE OF CONTENTS

NORTHEAST UTILITIES AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARY

NSTAR ELECTRIC COMPANY AND SUBSIDIARIES

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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, including NSTAR LLC and its subsidiaries for periods after April 10, 2012.

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, financial performance or growth and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify our forward-looking statements through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materially from actual results. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward-looking statements, including, but not limited to:

.

the possibility that expected merger synergies will not be realized or will not be realized within the expected time period,

.

cyber breaches, acts of war or terrorism, or grid disturbances,

.

actions or inaction by local, state and federal regulatory and taxing bodies,

.

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

.

changes in weather patterns,

.

changes in laws, regulations or regulatory policy,

.

changes in levels and timing of capital expenditures,

.

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

.

developments in legal or public policy doctrines,

.

technological developments,

.

changes in accounting standards and financial reporting regulations,

.

actions of rating agencies, and

.

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 us to predict all of such factors, nor can we 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.

NORTHEAST UTILITIES AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

NSTAR ELECTRIC COMPANY AND SUBSIDIARIES

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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.

NU, headquartered in Boston, Massachusetts and 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;

NSTAR Electric Company (NSTAR Electric), a regulated electric utility that serves residential, commercial and industrial customers in parts of Massachusetts;

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;

NSTAR Gas Company (NSTAR Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Massachusetts; 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 subsidiaries, NU Enterprises and NSTAR LLC, which are included in its Parent and other companies results of operations.

Although NU, CL&P, NSTAR Electric, PSNH and WMECO each report their financial results separately, we also include information in this report on a segment, or line-of-business, basis. The Regulated companies' segments include the electric distribution segment, the natural gas distribution segment and the electric transmission segment. The electric distribution segment includes the generation businesses of PSNH and WMECO. The Regulated companies' segments represented substantially all of NU's total consolidated revenues for years ended December 31, 2012 and 2011.

MERGER WITH NSTAR

On April 10, 2012, NU completed its merger with NSTAR (Merger). Pursuant to the terms and conditions of the Agreement and Plan of Merger, as amended, NSTAR was merged with and into a wholly owned subsidiary of NU, which was subsequently renamed NSTAR LLC. NU s consolidated financial statements include the results of operations of NSTAR LLC and its subsidiaries for the period after April 10, 2012.

ELECTRIC DISTRIBUTION SEGMENT

General

NU s electric distribution segment consists of the distribution businesses of CL&P, NSTAR Electric, PSNH and WMECO, which are engaged in the distribution of electricity to retail customers in Connecticut, eastern Massachusetts, New Hampshire and western Massachusetts, respectively, plus the regulated electric generation businesses of PSNH and WMECO.

The following table shows the sources of 2012 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers, including the electric franchise retail revenues of NSTAR Electric from the date of merger, April 10, 2012, through December 31, 2012:

(Thousands of Dollars, except percentages)		**2012**	**% of Total**
Residential	$	2,731,951	52
Commercial		1,563,709	30
Industrial		753,974	14
Streetlighting and Railroads		40,952	1
Miscellaneous and Eliminations		130,137	3
Total Retail Electric Revenues	$	5,220,723	100%

A summary of our distribution companies retail electric GWh sales and percentage changes for 2012, as compared to 2011, is as follows:

	2012 (1)	**2011**	**Percentage Change**
Residential	19,719	14,766	33.5%
Commercial	24,117	14,301	68.6%
Industrial	5,462	4,418	23.6%
Other	420	327	28.6%
Total	49,718	33,812	47.0%

(1)

NU retail electric sales include the sales of NSTAR Electric from the date of merger, April 10, 2012, through December 31, 2012.

Actual retail electric sales for CL&P, NSTAR Electric and WMECO decreased in 2012, as compared to 2011, due primarily to the warmer than normal weather in the first quarter of 2012, as compared to colder than normal weather in the first quarter of 2011, while actual retail electric sales for PSNH were 0.1 percent higher than last year. In 2012, heating degree days were 11 percent lower in Connecticut and western Massachusetts, 7 percent lower in the Boston metropolitan area, and 9 percent lower in New Hampshire, as compared to 2011. On a weather normalized basis (based on 30-year average temperatures), the average NU combined consolidated total retail electric sales decreased 0.2 percent in 2012, as compared to 2011, assuming NSTAR Electric had been part of the NU combined electric distribution system for all periods under consideration. We believe these decreases were due primarily to increased conservation efforts among all our customer classes and the continued installation of distributed generation at our commercial and industrial customers facilities. 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 annual level of baseline distribution delivery service revenues of $125.4 million that it is able to recover. This effectively breaks the relationship between sales volume and revenues recognized.

Major Storms

On August 28, 2011, Tropical Storm Irene caused extensive damage to our distribution system. Approximately 800,000 CL&P, PSNH and WMECO customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut. Approximately 500,000 customer outages occurred on the NSTAR Electric distribution system in its aftermath.

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 CL&P, PSNH and WMECO s 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 western 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; and the most severe in WMECO's history. The storm also caused approximately 200,000 customer outages on the NSTAR Electric distribution system.

On October 29, 2012, Hurricane Sandy caused extensive damage to our electric distribution system across all three states. Approximately 1.5 million of our 3.1 million electric distribution customers were without power during or following the storm, with approximately 850,000 of those customers in Connecticut, approximately 472,000 in Massachusetts, and approximately 137,000 in New Hampshire.

As of December 31, 2012, deferred storm restoration costs related to these major storms that are deferred for future recovery at CL&P, NSTAR Electric, PSNH, and WMECO were as follows:

(Millions of Dollars)	**Tropical Storm Irene**	**October Snowstorm**	**Hurricane Sandy**	**Total**
	$	$	$	$
CL&P	108.6	173.0	159.9	441.5
NSTAR Electric	21.9	13.9	27.8	63.6
PSNH	6.8	15.5	12.1	34.4
WMECO	3.2	23.3	4.2	30.7
	$	$	$	$
Total	140.5	225.7	204.0	570.2

On February 8, 2013, a blizzard caused damage to the electric delivery systems of CL&P and NSTAR Electric. We have estimated that approximately 71,000 and 350,000 of CL&P and NSTAR Electric's distribution customers, respectively, were without power during or following the storm. We believe that this storm will cost between $100 million to $120 million, with approximately 90 percent of those costs relating to NSTAR Electric. Management expects the costs to meet the criteria for specific cost recovery in Connecticut and Massachusetts and, as a result, does not expect the storm to have a material impact on the results of operations of CL&P or NSTAR Electric. Each operating company will seek recovery of these anticipated deferred storm costs through its applicable regulatory recovery process.

ELECTRIC DISTRIBUTION CONNECTICUT

THE CONNECTICUT LIGHT AND POWER COMPANY

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, 2012, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 cities and towns in Connecticut, covering an area of 4,400 square miles. CL&P does not own any electric generation facilities.

The following table shows the sources of CL&P s 2012 electric franchise retail revenues based on categories of customers:

		CL&P	
(Thousands of Dollars, except percentages)		**2012**	**% of Total**
Residential	$	1,263,845	58
Commercial		711,337	32
Industrial		126,165	6
Streetlighting and Railroads		21,283	1
Miscellaneous		70,012	3
Total Retail Electric Revenues	$	2,192,642	100%

A summary of CL&P s retail electric GWh sales and percentage changes for 2012, as compared to 2011, is as follows:

	2012	2011	Percentage Change
Residential	9,978	10,092	(1.1)%
Commercial	9,414	9,525	(1.2)%
Industrial	2,426	2,414	0.5 %
Other	291	284	2.3 %
Total	22,109	22,315	(0.9)%

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

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.

The distribution rates established by the PURA for CL&P are comprised of the following:

.

GSC charge (the electric generation services component), which recovers energy-related costs incurred as a result of providing electric generation service supply to all customers that have not migrated to competitive energy suppliers. The GSC charge is adjusted periodically and reconciled semi-annually in accordance with the directives of PURA. Expense/revenue reconciliation amounts are recovered in subsequent rates.

4

.

FMCC charge, which recovers any costs imposed by the FERC as part of the New England Standard Market Design, including locational marginal pricing, locational installed capacity payments, any cost approved by PURA to reduce FMCC charges (with conditions) and reliability must run contracts. The FMCC charge is adjusted periodically and reconciled semi-annually in accordance with the directives of PURA. Expense/revenue reconciliation amounts are recovered in subsequent rates.

.

SBC charge, established to fund expenses for the public education outreach program, costs associated with various hardship and low income programs, a program to compensate municipalities for losses in property tax revenue due to decreases in the value of electric generating facilities resulting directly from electric industry restructuring, displaced worker protection costs, unfunded storage and disposal costs for spent nuclear fuel generated before January 1, 2000, and decommissioning fund contributions. Any element of the SBC charge may be revised by PURA as the need arises. The SBC charge is reconciled annually to actual costs incurred, with any difference refunded to, or recovered from, customers.

.

CTA charge, which pays the principal and interest on RRBs as well as the reasonable and necessary costs related to the RRBs financing. The CTA charge is also assessed to recover stranded costs associated with electric industry restructuring as well as various IPP contracts that were not funded with the proceeds of the RRBs. The CTA charge is reconciled annually to actual costs incurred, with any difference refunded to, or recovered from, customers.

.

The Renewable Energy Investment Fund charge, which is used to promote investment in renewable energy sources. Funds collected by this charge are deposited into the Renewable Energy Investment Fund and administered by Connecticut Innovations, Incorporated. The Renewable Energy Investment Fund charge is set by statute and is currently 0.1 cent per kWh.

.

C&LM charge, established to implement cost-effective energy conservation programs and market transformation initiatives.

.

Transmission adjustment clause, which reconciles on a semi-annual basis the transmission revenues billed to customers against the transmission costs of acquiring such services, to recover 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 consisting of three generation projects 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.

CL&P, jointly with UI, has entered into three CfDs (each having a 80 percent to 20 percent sharing mechanism as described above), with developers of peaking generation units approved by the PURA (Peaker CfDs). These units have a total of approximately 500 MW of peaking capacity. The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. 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.

On June 30, 2010, PURA issued a final order in CL&P s most recent retail distribution rate case approving distribution rates and establishing CL&P s authorized distribution regulatory ROE at 9.4 percent.

On March 13, 2012, NU and NSTAR reached a comprehensive settlement agreement with both the Connecticut Attorney General and the Connecticut Office of Consumer Counsel related to the Merger. The settlement agreement covered a variety of matters, including a CL&P base distribution rate freeze until December 1, 2014. The settlement agreement also provided for a $25 million rate credit to CL&P customers and the establishment of a $15 million fund for energy efficiency and other initiatives to be disbursed at the direction of the DEEP. CL&P also agreed to forego rate recovery of $40 million of deferred storm costs associated with restoration activities following Tropical Storm Irene and the October 2011 snowstorm. On April 2, 2012, the PURA approved the settlement agreement and the Merger.

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 for the first half of 2013, and 70 percent of expected load for the second half of 2013. CL&P intends to purchase 10 percent of the SS load for the second half of 2013. None of the SS load for 2014 has been procured. CL&P s contracts for its LRS loads extend through the second quarter of 2013, and CL&P intends to purchase 10 percent of the LRS load for the third quarter of 2013.

ELECTRIC DISTRIBUTION MASSACHUSETTS

NSTAR ELECTRIC COMPANY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

The electric distribution businesses of NSTAR Electric and WMECO consist primarily of the purchase, delivery and sale of electricity to residential, commercial and industrial customers within their respective franchise service territories. As of December 31, 2012, NSTAR Electric furnished retail franchise electric service to approximately 1.1 million customers in Boston and 80 surrounding cities and towns in Massachusetts, including Cape Cod and Martha s Vineyard, covering an area of 1,702 square miles. WMECO provides retail franchise electric service to approximately 207,000 retail customers in 59 cities and towns in the western region of Massachusetts, covering an area of 1,500 square miles. Neither NSTAR Electric nor WMECO owns any fossil or hydro-electric generating facilities, and each purchases its respective energy requirements from competitive suppliers.

In 2009, WMECO was authorized by the DPU 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. In connection with the Attorney General settlement agreement (as defined below) that approved the Merger in Massachusetts, WMECO committed to increase its solar generation capacity to 8 MW. WMECO is continuing to evaluate sites suitable for development of the remaining 3.9 MW of capacity. WMECO will sell all energy and other products from its solar generation facilities into the ISO-NE market. NSTAR Electric does not own any solar generating facilities, but agreed to issue a request for proposals to enter into long-term contracts for 10 megawatts of solar power in connection with the Attorney General settlement agreement that approved the Merger in Massachusetts. NSTAR Electric has entered in two contracts for 5 MW of capacity, which contracts are still pending approval at the DPU.

The following table shows the sources of the 2012 electric franchise retail revenues of NSTAR Electric and WMECO based on categories of customers:

	NSTAR Electric		**WMECO**	
(Thousands of Dollars, except percentages)	**2012**	**% of Total**	**2012**	**% of Total**

Residential	$ 1,000,038	44	$ 213,494	55
Commercial	1,101,575	48	123,651	32
Industrial	94,130	4	40,207	10
Streetlighting and Railroads	13,047	1	3,780	1
Miscellaneous	85,885	3	5,973	2
Total Retail Electric Revenues	$ 2,294,675	100%	$ 387,105	100%

A summary of NSTAR Electric s and WMECO s retail electric GWh sales and percentage changes for 2012, as compared to 2011, is as follows:

	NSTAR Electric			WMECO		
	2012	**2011**	**Percentage Change**	**2012**	**2011**	**Percentage Change**
Residential	6,741	6,727	0.2 %	1,517	1,533	(1.0)%
Commercial	12,987	13,211	(1.7)%	1,485	1,474	0.7 %
Industrial	1,353	1,418	(4.6)%	663	669	(0.9)%
Other	128	146	(12.2)%	18	19	(5.7)%
Total	21,209	21,502	(1.4)%	3,683	3,695	(0.3)%

Rates

NSTAR Electric and WMECO are each 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. The present general rate structure for both NSTAR Electric and WMECO 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 customers of each of NSTAR Electric and WMECO are entitled to choose their energy suppliers, while NSTAR Electric or WMECO, as the case may be, remains their distribution company. Both NSTAR Electric and WMECO purchase power from competitive suppliers for, and pass through the cost to, their respective customers who do not choose a competitive energy supplier (basic service). Basic service charges are adjusted and reconciled on an annual basis. Most of the residential and small commercial and industrial customers of NSTAR Electric and WMECO have continued to buy their power from NSTAR Electric or WMECO, as the case may be, at basic service rates. Most large commercial and industrial customers have switched to a competitive energy supplier.

The Cape Light Compact, an inter-governmental organization consisting of the 21 towns and two counties on Cape Cod and Martha s Vineyard, serves 200,000 customers through the delivery of energy efficiency programs, effective consumer advocacy, competitive electricity supply and green power options. NSTAR Electric continues to provide electric service to these customers including the delivery of power, meter reading, billing, and customer service.

NSTAR Electric continues to supply approximately 40 percent of its customer load at basic service rates while the other 60 percent of its customer load has migrated to competitive energy suppliers. WMECO continues to supply approximately 49 percent of its customer load at basic service rates while the other 51 percent of its customer load has migrated to competitive energy suppliers. Because customer migration is limited to energy supply service, it has no impact on the delivery business or operating income of NSTAR and WMECO.

The distribution rates established by the DPU for NSTAR Electric and WMECO are comprised of the following:

.

A distribution charge, which includes a fixed customer charge and a demand and/or energy charge to collect the costs of building and expanding the infrastructure to deliver power to its destination, as well as ongoing operating costs. The distribution charge also includes the recovery, on a fully reconciling basis, of certain DPU-approved safety and reliability program costs, a Pension and PBOP Rate Adjustment Mechanism (PAM) to recover incremental pension and PBOP benefit costs, a reconciling rate adjustment mechanism to recover costs associated with the residential assistance adjustment clause, a net-metering reconciliation surcharge to collect the lost revenues and credits associated with net-metering facilities installed by customers, and an Energy Efficiency Reconciling Factor (EERF) to recover energy efficiency program costs and lost base revenues in addition to those charges recovered in the energy conservation charge.

.

A basic service charge represents the collection of energy costs, including costs related to charge-offs of uncollected energy costs, through DPU-approved rate mechanisms. Electric distribution companies in Massachusetts are required to obtain and resell power to retail customers through basic service for those who choose not to buy energy from a competitive energy supplier. Basic service rates are reset every six months (every three months for large commercial and industrial customers). The price of basic service is intended to reflect the average competitive market price for electric power. Additionally, the DPU has authorized NSTAR Electric to recover the cost of its Dynamic Pricing Smart Grid Pilot Program through the basic service charge.

.

A transition charge represents costs to be collected primarily from previously held investments in generating plants, costs related to existing above-market power contracts, and contract costs related to long-term power contracts buy-outs.

.

A transmission charge to recover the costs of transporting electricity over high voltage lines from generating plants to substations, including costs allocated by ISO-NE to maintain the wholesale electric market.

.

An energy conservation charge represents a legislatively-mandated charge to collect costs for energy efficiency programs.

.

A renewable energy charge represents a legislatively-mandated charge to collect the costs to support the development and promotion of renewable energy projects.

Rate Settlement Agreement

On February 15, 2012, NU and NSTAR reached comprehensive settlement agreements with the Massachusetts Attorney General (Attorney General settlement agreement) and the DOER related to the Merger. The Attorney General settlement agreement covered a variety of rate-making and rate design issues, including a base distribution rate freeze through 2015 for NSTAR Electric and WMECO, a rate credit of $15 million to customers of NSTAR Electric and a rate credit of $3 million to customers of WMECO. The settlement agreement reached with the DOER covered the same rate-making and rate design issues as the Attorney General's settlement agreement, as well as a variety of matters impacting the advancement of Massachusetts clean energy policy established by the Green Communities Act and Global Warming Solutions Act. On April 4, 2012, the DPU approved the settlement agreements and the Merger.

NSTAR Electric is operating under a DPU-approved Rate Settlement Agreement (Rate Settlement Agreement) that was scheduled to expire on December 31, 2012. As noted above, the rates under the Rate Settlement Agreement are subject to a base distribution rate freeze through 2015 pursuant to the Attorney General settlement agreement. Pursuant to a 2008 DPU order, Massachusetts electric utilities must adopt rate structures that decouple the volume of energy sales from the utility s revenues in their next rate case. The exact timing of NSTAR Electric s next rate case has not yet been determined, but it will not be before 2015.

In WMECO s January 31, 2011 rate decision, the DPU approved 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 rates under the January 31, 2011 rate decision are subject to a base distribution rate freeze through 2015 pursuant to the Attorney General settlement agreement .

NSTAR Electric and WMECO are each subject to service quality (SQ) metrics that measure safety, reliability and customer service, and must pay to customers any charges incurred for failure to meet such metrics. Neither NSTAR Electric nor WMECO will be required to pay an assessment charge for its 2012 performance results as both companies performed at or above target for all of their respective SQ metrics in 2012.

Sources and Availability of Electric Power Supply

As noted above, neither NSTAR Electric nor WMECO owns any generation assets (other than WMECO s recently constructed solar generation), and both companies purchase their respective energy requirements from a variety of competitive sources through requests for proposals issued periodically, consistent with DPU regulations. NSTAR Electric and WMECO enter into supply contracts for basic service for 50 percent of their respective residential and small commercial and industrial customers twice a year for twelve month terms. Both NSTAR Electric and WMECO enter into supply contracts for basic service for 100 percent of large commercial and industrial customers every three months.

ELECTRIC DISTRIBUTION NEW HAMPSHIRE

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

PSNH s distribution business consists primarily of the generation, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2012, PSNH furnished retail franchise electric service to approximately 500,000 retail customers in 211 cities and towns in New Hampshire, covering an area of 5,628 square miles. 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 business includes the activities of its generation business.

The Clean Air Project, a wet flue gas desulphurization system (Scrubber), was constructed and placed in service by PSNH at its Merrimack Station in September 2011. The cost of the Scrubber is expected to 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 completed remaining project construction activities in 2012 and the final cost of the project was approximately $421 million.

The Clean Air Project was placed in service and began operations nearly two years before the statutory deadline of July 1, 2013. Tests to date indicate that the Scrubber reduces emissions of SO_2 and mercury from Merrimack Station by over 90 percent, which is well in excess of state and federal requirements. Notwithstanding the Clean Air Project's environmental successes well in advance of the statutory deadline, competitors and environmental groups continue to challenge PSNH's right to recover the costs of this legally-mandated project. In particular, TransCanada, a Canadian energy company that is pursuing the transcontinental Keystone XL pipeline across the United States and is a participant in the U.S. competitive electricity market, and the Conservation Law Foundation, an environmental group which initially supported the law requiring installation of the Scrubber and which formally notified PSNH that it intended to sue PSNH under the Clean Air Act for not installing such emissions control technology, both now claim PSNH was imprudent for pursuing the Clean Air Project. PSNH is vigorously defending its constitutionally protected right to recover the costs of the Clean Air Project, which were invested to comply with the express mandates of state law.

The following table shows the sources of PSNH s 2012 electric franchise retail revenues based on categories of customers:

		PSNH	
(Thousands of Dollars, except percentages)		**2012**	**% of Total**
Residential	$	511,036	54
Commercial		313,201	33
Industrial		82,141	9
Streetlighting and Railroads		6,061	1
Miscellaneous		33,948	3
Total Retail Electric Revenues	$	946,387	100%

A summary of PSNH s retail electric GWh sales and percentage changes for 2012, as compared to 2011, is as follows:

	2012	**2011**	**Percentage Change**
Residential	3,138	3,141	(0.1)%
Commercial	3,315	3,315	0.0 %
Industrial	1,345	1,336	0.7 %
Other	23	23	(1.0)%
Total	7,821	7,815	0.1 %

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. New Hampshire 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 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 2012, approximately 9.4 percent of all of PSNH s customers (approximately 44 percent of load), mostly large commercial and industrial customers, had switched to competitive energy suppliers. This was an increase from 2011, when 2.6 percent of customers (approximately 36 percent of load) 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. On April 27, 2012, PSNH filed its proposed Alternative Default Energy Service Rate that addresses customer migration, with an effective date of July 1, 2012. The proposal, if implemented, would result in no impact to earnings and would allow for an increased contribution to fixed costs for all ES customers. Hearings were held on October 18, 2012 and November 26, 2012. A final decision is expected in the first quarter of 2013.

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.

The distribution rates established by the NHPUC for PSNH are comprised of the following:

.

ES charge, which recovers PSNH s generation and purchased power costs from customers on a current basis and allows for an ROE of 9.81 percent on its generation investment.

.

SCRC, which 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.

.

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

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. On December 28, 2012, the NHPUC issued orders approving PSNH s requests to adjust its ES and SCRC rates effective with service rendered on and after January 1, 2013. The orders approve an increase to the ES billing rate to reflect projected costs for 2013 and a decrease to the SCRC billing rate to reflect the full amortization of RRBs as of May 1, 2013. The impact to customers that purchase energy from PSNH is a net increase of 1.287 cents per kWh in total rates.

On June 28, 2010, the NHPUC approved a joint settlement of PSNH's rate case. Under the approved settlement, if PSNH's 12-month rolling average ROE for distribution exceeds 10 percent, amounts over the 10 percent level are to be allocated 75 percent to customers and 25 percent to PSNH. Additionally, the settlement provided that the authorized regulatory ROE on distribution plant would continue at the previously allowed level of 9.67 percent, and also permitted PSNH to file a request to collect certain exogenous costs and step increases on an annual basis. In 2012, PSNH filed for a step increase and a change in its accrual to its major storm reserve fund. On June 27, 2012, the NHPUC approved an annualized distribution rate increase of $7.1 million effective July 1, 2012, for the step increase. Additionally, PSNH was allowed a $3.5 million increase in the annual accrual to its major storm reserve fund effective July 1, 2012.

On November 22, 2011, the NHPUC opened a docket to review the Clean Air Project including the establishment of temporary rates for near-term recovery of Clean Air Project costs, a prudence review of PSNH's overall construction program, and establishment of permanent rates for recovery of prudently incurred Clean Air Project costs. On April 10, 2012, the NHPUC issued an order authorizing temporary rates, effective April 16, 2012, which recover a significant portion of the Clean Air Project costs, including a return on equity. The docket will continue for a comprehensive prudence review of the Clean Air Project and the establishment of a permanent rate. The temporary rates will remain in effect until a permanent rate allowing full recovery of all prudently incurred costs is approved. At that time,

the NHPUC will reconcile recoveries collected under the temporary rates with final approved rates. PSNH expects hearings to commence in this proceeding on or about the third quarter of 2013. PSNH believes that its actions related to Clean Air Project construction will be deemed prudent. The project was completed for $421 million, approximately $36 million below budget, and has reduced mercury and sulfur emissions by more than 90 percent. On September 6, 2012, a consultant for the NHPUC filed a report with the NHPUC concluding that PSNH had effectively managed the Clean Air Project.

Sources and Availability of Electric Power Supply

During 2012, approximately 59 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 41 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 2013 in a similar manner. Included in the 59 percent above are PSNH s 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.

NATURAL GAS DISTRIBUTION SEGMENT

General

NU s natural gas distribution segment consists of the distribution businesses of NSTAR Gas and Yankee Gas, which are engaged in the distribution of natural gas to retail customers in eastern Massachusetts and Connecticut, respectively.

The following table shows the sources of the 2012 natural gas franchise retail revenues of NSTAR Gas and Yankee Gas based on categories of customers:

	NSTAR Gas[(1)]		Yankee Gas	
(Thousands of Dollars, except percentages)	**2012**	**% of Total**	**2012**	**% of Total**
Residential	$ 212,428	63	$ 194,110	52

Commercial		110,493	33		118,124	32
Industrial		14,243	4		61,767	16
Total Retail Natural Gas Revenues	$	337,164	100%	$	374,001	100%

(1)

NSTAR Gas revenue for the full-year ended December 31, 2012, has been provided for comparative purposes only.

A summary of NSTAR Gas and Yankee Gas retail firm natural gas sales and percentage changes in million cubic feet for 2012, as compared to 2011, is as follows:

	NSTAR Gas[1]			Yankee Gas		
	2012	**2011**	**Percentage Change**	**2012**	**2011**	**Percentage Change**
Residential	18,385	20,595	(10.7)%	12,488	13,508	(7.6)%
Commercial	19,095	19,662	(2.9)%	16,567	17,175	(3.5)%
Industrial	5,205	5,226	(0.4)%	15,787	16,197	(2.5)%
Total	42,685	45,483	(6.2)%	44,842	46,880	(4.3)%
Total, Net of Special Contracts [2]				39,087	38,197	2.3 %

(1)

NSTAR Gas sales data for the full-year ended December 31, 2012 compared to 2011 has been provided for comparative purposes only.

(2)

Special contracts are unique to the Yankee Gas 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 our retail electric sales, but have benefitted from lower natural gas prices and customer growth across all three customer classes. In 2012, excluding the impact of NSTAR Gas sales, actual sales decreased, as compared to 2011, due primarily to the warmer than normal weather in the first quarter of 2012, as compared to colder than normal weather in the first quarter of 2011. On a weather normalized basis, Yankee Gas 2012 sales increased due primarily to customer growth, lower cost of natural gas, the migration of interruptible customers switching to firm service rates, and the addition of gas-fired distributed generation in Yankee Gas service territory.

On a weather-normalized basis, the average NU combined consolidated total firm natural gas sales increased 2.7 percent in 2012, as compared to 2011, assuming NSTAR Gas had been part of the NU combined natural gas distribution system for all periods under consideration.

NSTAR GAS COMPANY

NSTAR Gas distributes natural gas to approximately 272,000 customers in 51 communities in central and eastern Massachusetts covering 1,067 square miles. Total throughput (sales and transportation) in 2012 was approximately 60.5 Bcf. NSTAR 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 NSTAR Gas.

Rates

NSTAR Gas generates revenues primarily through the sale and/or transportation of natural gas. Gas sales and transportation services are divided into two categories: firm, whereby NSTAR Gas must supply gas and/or transportation services to customers on demand; and interruptible, whereby NSTAR Gas may, generally during colder months, temporarily discontinue service to high volume commercial and industrial customers. Sales and transportation of gas to interruptible customers have no impact on NSTAR Gas operating income because a substantial portion of the margin for such service is returned to its firm customers as rate reductions.

The Attorney General settlement agreement that approved the Merger provided for a rate freeze through 2015 and a rate credit of $3 million to NSTAR Gas customers.

Retail natural gas delivery and supply rates are established by the DPU and are comprised of:

.

A distribution charge consisting of a fixed customer charge and a demand and/or energy charge that collects the costs of building and expanding the natural gas infrastructure to deliver natural gas supply to its customers. This also includes collection of ongoing operating costs;

.

A seasonal cost of gas adjustment clause (CGAC) that collects natural gas supply costs, pipeline and storage capacity costs, costs related to charge-offs of uncollected energy costs and working capital related costs. The CGAC is reset every six months. In addition, NSTAR Gas files interim changes to its CGAC factor when the actual costs of natural gas supply vary from projections by more than 5 percent; and

.

A local distribution adjustment clause (LDAC) that collects energy efficiency program costs, environmental costs, PAM related costs, and costs associated with the residential assistance adjustment clause. The LDAC is reset annually and provides for the recovery of certain costs applicable to both sales and transportation customers.

NSTAR Gas purchases financial contracts based on NYMEX natural gas futures in order to reduce cash flow variability associated with the purchase price for approximately one-third of its natural gas purchases. These purchases are made under a program approved by the Massachusetts Department of Public Utilities in 2006. This practice attempts to minimize the impact of fluctuations in prices to NSTAR Gas firm gas customers. These financial contracts do not procure gas supply. All costs incurred or benefits realized when these contracts are settled are included in the CGAC.

Sources and Availability of Natural Gas Supply

NSTAR Gas maintains a flexible resource portfolio consisting of natural gas supply contracts, transportation contracts on interstate pipelines, market area storage and peaking services. NSTAR Gas purchases transportation, storage, and balancing services from Tennessee Gas Pipeline Company and Algonquin Gas Transmission Company, as well as other upstream pipelines that transport gas from major producing regions in the U.S., including Gulf Coast, Mid-continent, and Appalachian Shale supplies to the final delivery points in the NSTAR Gas service area. NSTAR Gas purchases all of its natural gas supply from a firm portfolio management contract with a term of one year, which has a maximum quantity of approximately 139,500 MMBtu/day.

In addition to the firm transportation and natural gas supplies mentioned above, NSTAR Gas utilizes contracts for underground storage and LNG facilities to meet its winter peaking demands. The LNG facilities, described below, are located within NSTAR Gas distribution system and are used to liquefy and store pipeline gas during the warmer months for vaporization and use during the heating season. During the summer injection season, excess pipeline capacity and supplies are used to deliver and store natural gas in market area underground storage facilities located in the New York and Pennsylvania region. Stored natural gas is withdrawn during the winter season to supplement flowing pipeline supplies in order to meet firm heating demand. NSTAR Gas has firm underground storage contracts and total storage capacity entitlements of approximately 6.6 Bcf.

A portion of the storage of natural gas supply for NSTAR Gas during the winter heating season is provided by Hopkinton, a wholly-owned subsidiary of NSTAR LLC. The facilities consist of an LNG liquefaction and vaporization plant and three above-ground cryogenic storage tanks in Hopkinton, Massachusetts having an aggregate capacity of 3.0 Bcf of liquefied natural gas. NSTAR Gas also has access to facilities in Acushnet, Massachusetts that include additional storage capacity of 0.5 Bcf and additional vaporization capacity.

Based on information currently available regarding projected growth in demand and estimates of availability of future supplies of pipeline natural gas, NSTAR Gas believes that participation in planned and anticipated pipeline expansion projects will be required in order for it to meet current and future sales growth opportunities.

YANKEE GAS SERVICES COMPANY

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 212,000 customers in 71 cities and towns), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in 2012 was approximately 51 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.

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.

Retail natural gas delivery and supply rates are established by the PURA and are comprised of:

.

A distribution charge consisting of a fixed customer charge and a demand and/or energy charge that collects the costs of building and expanding the natural gas infrastructure to deliver natural gas supply to its customers. This also includes collection of ongoing operating costs;

.

Purchased Gas Adjustment (PGA) clause, which allows Yankee Gas to recover the costs of the procurement of natural gas for its firm and seasonal customers. Differences between actual natural gas costs and collection amounts on August 31st of each year are deferred and then recovered or returned to customers during the following year. Carrying charges on outstanding balances are calculated using Yankee Gas' weighted average cost of capital in accordance with the directives of the PURA; and

.

Conservation Adjustment Mechanism (CAM), which allows 100 percent recovery of conservation costs through this mechanism, with a return. The reconciliation process produces deferrals for future recovery or refund in future customer rates each year.

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.

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 Yankee Gas 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. Based on information currently available regarding projected growth in demand and estimates of availability of future supplies of pipeline natural gas, Yankee Gas believes that its present sources of natural gas supply are adequate to meet existing load and allow for future growth in sales.

ELECTRIC TRANSMISSION SEGMENT

General

CL&P, NSTAR Electric, 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 businesses of CL&P, NSTAR Electric, 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 50 basis points for joining a 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, NSTAR Electric earns between 11.64 percent and 12.64 percent on its major transmission projects, and WMECO earns 12.89 percent on the Massachusetts portion of GSRP.

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, NSTAR Electric, 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, which would be effective September 30, 2011 through December 31, 2012. In response, the New England transmission owners filed testimony and analysis based on standard FERC methodology and precedent, demonstrating that the base ROE of 11.14 percent remained just and reasonable.

On May 3, 2012, the FERC issued an order establishing hearing and settlement procedures for the complaint. The settlement proceedings were subsequently terminated, as the parties had reached an impasse in their efforts to reach a settlement. In August 2012, the FERC trial judge assigned to the complaint established a schedule for the trial phase of the proceedings. Complainant testimony supporting a base ROE of 9 percent was filed on October 1, 2012. Additional testimony was filed on October 1, 2012 by a group of Massachusetts municipal electric companies, which recommended a base ROE of 8.2 percent. The New England transmission owners filed testimony and analysis on November 20, 2012, demonstrating they believe that the current base ROE continues to be just and reasonable. On January 18, 2013, the FERC trial staff filed testimony and analysis recommending a base ROE of 9.66 percent based on the midpoint of their analysis with a range of reasonableness of 6.82 percent to 12.51 percent. The New England transmission owners criticized trial staff's analysis in responsive testimony filed on February 12, 2013. Complainants' final testimony is due February 27, 2013. Hearings on this complaint are scheduled for May 2013 and a trial judge s recommended decision is due in September 2013. A decision from FERC commissioners is expected in 2014. Refunds to customers, if any, as a result of a reduction in the NU transmission companies base ROE would be retroactive to October 1, 2011.

On December 27, 2012, several additional parties filed a separate complaint concerning the New England transmission owners' ROE with the FERC. This new complaint seeks to reduce the New England transmission owner s base transmission ROE effective January 1, 2013, and to consolidate this new complaint with the joint complaint filed on September 30, 2011. The New England transmission owners have asked the FERC to reject this new complaint, and the FERC has not yet acted on it.

As of December 31, 2012, CL&P, NSTAR Electric, PSNH, and WMECO had approximately $2.1 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 $2.1 million. We cannot at this time predict the ultimate outcome of this proceeding or the estimated impact on CL&P s, NSTAR Electric s, PSNH s, or WMECO s respective financial position, results of operations or cash flows.

FERC Order No. 1000: On October 25, 2012, ISO-NE and a majority of the New England transmission owners, including CL&P, NSTAR Electric, PSNH and WMECO, made a comprehensive compliance filing as required by FERC Order No. 1000 and Order No. 1000-A, issued on July 21, 2011 and May 17, 2012, respectively. The compliance filing first seeks to preserve the existing reliability planning process in New England, based on FERC s previous approval of transmission owners rights under the Transmission Operating Agreement with ISO-NE, and the superiority of the current planning process, which has resulted in major transmission construction, large reliability benefits and reduction of market costs. The filing also contains a new process for public policy transmission planning that incorporates opportunities for competing, non-incumbent projects and cost allocation among the supporting states. In mid-January 2013, ISO-NE and the majority of New England transmission owners filed answers to various stakeholders that submitted protests to the compliance filing. We cannot predict the final outcome or impact on us; however implementation of FERC s goals in New England, including within our service territories, may expose us to competition for construction of transmission projects, additional regulatory considerations, and potential delay with respect to future transmission projects.

Transmission Projects

NEEWS: GSRP, a project that involves the construction of 115 kV and 345 kV overhead lines by CL&P and WMECO from Ludlow, Massachusetts to Bloomfield, Connecticut, is the first, largest and most complicated project within the NEEWS family of projects. The $718 million project is expected to be fully placed in service in late 2013. As of December 31, 2012, the project was approximately 93 percent complete and we have placed $298 million in service.

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. All siting applications have been filed by CL&P and National Grid. On January 2, 2013, the Connecticut Siting Council issued a final decision and order approving the Connecticut portion of the project. Decisions in Rhode Island and Massachusetts are expected between the end of 2013 and early 2014. The $218 million project is expected to be placed in service in late 2015.

Included as part of NEEWS are associated reliability related projects, approximately $70 million of which have been placed in service and approximately $30 million of which are in various phases of construction and will continue to go into service through 2013.

Through December 31, 2012, CL&P and WMECO had capitalized $212 million and $518.1 million, respectively, in costs associated with NEEWS, of which $79.4 million and $183.4 million, respectively, were capitalized in 2012.

Greater Hartford Central Connecticut Project (GHCC): In August 2012, ISO-NE presented its preliminary needs analysis for the GHCC to the ISO-NE Planning Advisory Committee. The results showed severe thermal overloads and voltage violations in each of the four study areas now and in the near future. A combination of 345 kV and 115 kV transmission solutions are being considered to address these reliability concerns and a set of preferred solutions are expected to be identified by ISO-NE in 2013. Approximately $300 million has been included in our five-year capital program for future projects being identified to enhance these reliability concerns, which have recently been confirmed by ISO-NE.

Cape Cod Reliability Projects: Transmission projects serving Cape Cod in the Southeastern Massachusetts (SEMA) reliability region consist of an expansion and upgrade of NSTAR Electric's existing transmission infrastructure including construction of a new 345 kV transmission line that will cross the Cape Cod Canal (The Lower SEMA Transmission Project) as well as a new 115kV transmission line and other 115kV upgrades in the center of Cape Cod. All regulatory and licensing and permitting is complete for the Lower SEMA Transmission Project. Construction commenced in September 2012 and is expected to be completed by mid-2013. The total estimated construction cost for the Cape Cod projects is approximately $150 million.

Northern Pass: Northern Pass is NPT's 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. Effective April 10, 2012, as a result of the merger, NUTV owned 100 percent of NPT. NPT has identified a new route in the northern-most part of the project s route where PSNH did not own any rights of way. We expect to file the new route with the DOE in the first quarter of 2013, and we believe that NPT will be completed in early 2017.

We estimate the costs of the Northern Pass transmission project will be approximately $1.2 billion (including capitalized AFUDC).

Greater Boston Reliability and Boston Network Improvements: As a result of continued analysis of the transmission needs to enhance system reliability and improve capacity in eastern Massachusetts, NSTAR Electric expects to implement a series of new transmission initiatives over the next five years. We have included $479 million in our five-year capital program related to these initiatives.

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 2012, our transmission rate base was approximately $4.2 billion, including approximately $2.2 billion at CL&P, $960 million at NSTAR Electric, $412 million at PSNH, and $620 million at WMECO.

CAPITAL EXPENDITURES

We project capital expenditures of approximately $5 billion from 2013 through 2015. Of the $5 billion, we expect to invest approximately $2.5 billion in our electric and natural gas distribution segments, including our generation businesses, and $2.3 billion in our electric transmission segment. In addition, we project capital expenditures of approximately $1.6 billion from 2016 through 2017 in our electric transmission segment.

FINANCING

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, NSTAR Electric, NSTAR Gas, NSTAR LLC, 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.

As of December 31, 2012, approximately $730 million of NU's long-term debt will be paid in the next 12 months, consisting of $550 million for NU parent, $55 million for WMECO, and $125 million for CL&P.

NUCLEAR DECOMMISSIONING

General

CL&P, NSTAR Electric, 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, NSTAR Electric, 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, NSTAR Electric, PSNH and WMECO in the Yankee Companies are set forth below:

	CL&P	NSTAR Electric	PSNH	WMECO	Total
CYAPC	34.5%	14.0%	5.0%	9.5%	63.0%
YAEC	24.5%	14.0%	7.0%	7.0%	52.5%
MYAPC	12.0%	4.0%	5.0%	3.0%	24.0%

Our share of the obligations to support the Yankee Companies under FERC-approved contracts is the same as the ownership percentages above. As a result of the Merger, we consolidate the assets and obligations of CYAPC and YAEC on our consolidated balance sheet.

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 NSTAR Electric, NSTAR Gas and 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 was fully operational by 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. The final cost of the project was approximately $421 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.

15

Water Quality Requirements

The Clean Water Act requires every point source discharger of pollutants into navigable waters to obtain a National Pollutant Discharge Elimination System (NPDES) permit from the 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 maintaining 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. In its filed comments, PSNH stated that the data and studies supplied to the EPA demonstrates the fact that a closed-cycle cooling system is not warranted. 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 there would be 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. Previously referred to as 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 two units at Merrimack Station, Newington

Station and the two coal units at Schiller Station. 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 incremental controls may be required for the two coal fired units at Schiller Station. To date, the financial impact of this potential control has not been determined.

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 2009 through 2011 are shown below.

	2011	2010	2009
Total CO_2-e emissions (excludes CO_2 from biomass and biofuels)	2,984	3,976	3,390

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.

Each of the states in which we do business also has Renewable Portfolio Standards (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 2012, the total RPS obligation was 13 percent and it will ultimately reach 26.5 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 typically sold to other energy suppliers or load carrying entities and the net proceeds from the sale of these RECs are credited back to customers.

16

Similarly, Connecticut's RPS statute requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2012, the total RPS obligation was 16 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 2012, the requirement was 16.6 percent, and will ultimately reach 27.1 percent in 2020. NSTAR Electric and WMECO are permitted to recover any costs incurred in complying with RPS from its customers through rates. WMECO also owns renewable solar generation resources. The RECs generated from WMECO s solar units are sold to other energy suppliers and the proceeds from these sales are credited back to customers.

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, 2012, 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 $39.4 million, representing 77 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 former MGP sites that have a reserve balance of $34.5 million of the total $39.4 million as of December 31, 2012.

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

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

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 that 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 greenhouse gas 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. These could include federal cap and trade laws, carbon taxes, fuel and energy taxes, or regulations requiring additional capital expenditures at our generating facilities. We expect that any costs of these rules and regulations would be recovered from customers.

Connecticut, New Hampshire and Massachusetts are each members of the Regional Greenhouse Gas Initiative (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 2012.

PSNH anticipates that its generating units will emit between two million and four million tons of CO_2 per year, depending on the capacity factor and the utilization of the plant, excluding emissions from the operation of PSNH s Northern Wood Power Project. New Hampshire legislation provides up to 1.5 million banked CO_2 allowances per year for PSNH s fossil fueled electric generating plants during the 2012 through 2014 compliance period. 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. Current legislation provides a portion of the RGGI auction proceeds in excess of $1 per allowance will be refunded to customers.

Because none of NU s other subsidiaries, CL&P, NSTAR Electric or WMECO, currently owns any generating assets (other than two solar photovoltaic facilities owned by WMECO, which do not emit CO_2), none of them is required to acquire CO_2 allowances. However, the CO_2 allowance costs borne by the generating facilities that are utilized by wholesale suppliers to satisfy energy supply requirements to CL&P, NSTAR Electric and WMECO will likely be included in the overall wholesale rates charged, which costs are then recoverable from customers.

Federal greenhouse gas legislation has stalled under the current administration. Recently, climate change law has been discussed as an initiative that will be moved forward in the current Congress. However, even without legislation, we can expect additional regulations from the EPA that could impact NU.

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. PSNH is currently involved with the early stages of relicensing at its Eastman Falls Hydro Station, which is comprised of two units, totaling 6.5 MW.

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, 2012, we employed a total of approximately 8,842 employees, excluding temporary employees, of which 1,787 were employed by CL&P, 1,204 were employed by PSNH, 348 were employed by WMECO, and 1,619 employees employed by NSTAR Electric & Gas Corporation provided services to NSTAR Electric. Approximately 47.8 percent of our employees are members of the International Brotherhood of Electrical Workers, the Utility Workers Union of America or The United Steelworkers, and are covered by 13 collective bargaining 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, NSTAR Electric s, PSNH's and WMECO'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 Merger may present certain material risks to the Company s business and operations.

The Merger, described in Item 1, *Business*, may present certain risks to our business and operations including, among other things, risks that:

.

We may be unable to successfully integrate the businesses and workforces of NSTAR with our businesses and workforces;

.

Conditions, terms, obligations or restrictions relating to the Merger imposed on us by regulatory authorities may adversely affect our business and operations;

.

We may be unable to avoid potential liabilities and unforeseen increased expenses or delays associated with integration plans;

.

We may be unable to successfully manage the complex integration of systems, technology, networks and other assets in a manner that minimizes any adverse impact on customers, vendors, suppliers, employees and other constituencies;

.

We may experience inconsistencies in each companies standards, controls, procedures and policies.

Accordingly, there can be no assurance that the Merger will result in the realization of the full benefits of synergies, innovation and operational efficiencies that we currently expect, that these benefits will be achieved within the anticipated timeframe or that we will be able to fully and accurately measure any such synergies.

Cyber breaches, acts of war or terrorism, or grid disturbances could negatively impact our business.

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.

Acts of war or terrorism could target our generation, 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.

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.

Any such cyber breaches, acts of war or terrorism, or grid disturbances 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.

Our goodwill is valued and recorded at an amount that, if impaired and written down, could adversely affect our future operating results and total capitalization.

We have a significant amount of goodwill on our consolidated balance sheet. The carrying value of goodwill represents the fair value of an acquired business in excess of identifiable assets and liabilities as of the acquisition date. As of December 31, 2012, goodwill totaled $3.5 billion, of which $3.2 billion was attributable to the acquisition of NSTAR in April 2012. Total goodwill represented approximately 38 percent of our $9.2 billion of shareholders equity and approximately 12 percent of our total assets of $28.3 billion. We perform an analysis of our goodwill balances to test for impairment on an annual basis or whenever events occur or circumstances change that would indicate a potential for impairment. A determination that goodwill is deemed to be impaired would result in a non-cash charge that could materially adversely affect our results of operations and total capitalization.

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, the October 29, 2011 snowstorm, Hurricane Sandy in October 2012, and the February 2013 blizzard, 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, the October 29, 2011 snowstorm, and Hurricane Sandy caused significant damage to our transmission and distribution systems. As a result, along with previously deferred costs from other storms, we have recorded approximately $548 million (approximately $414 million at CL&P) for estimated restoration costs as regulatory assets as of December 31, 2012, 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.

NU and its utility subsidiaries are exposed to significant reputational risks, which make them vulnerable to increased regulatory oversight or other sanctions.

Because utility companies, including our electric and natural gas utility subsidiaries, have large consumer customer bases, they are subject to adverse publicity focused on the reliability of their distribution services and the speed with which they are able to respond to electric outages, natural gas leaks and similar interruptions caused by storm damage or other unanticipated events. Adverse publicity of this nature could harm the reputations of NU and its subsidiaries, and may make state legislatures, utility commissions and other regulatory authorities less likely to view NU and its subsidiaries in a favorable light, and may cause NU and its subsidiaries to be subject to less favorable legislative and regulatory outcomes or increased regulatory oversight. Unfavorable regulatory outcomes can include more stringent laws and regulations governing our operations, such as reliability and customer service quality standards or vegetation management requirements, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material adverse effect on business, results of operations, cash flow and financial condition of NU and each of its utility subsidiaries.

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 and natural gas, 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; other unanticipated operations and maintenance expenses and liabilities; and potential claims for property damage or personal injuries beyond the scope of our insurance coverage. 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 could 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, NSTAR Electric 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, NSTAR Electric 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 may increase the cost to the remaining customers of energy produced by PSNH generation assets.

The competitiveness of PSNH s ES rates are sensitive to the cost of fuels, most notably natural gas, and customer load. Recently, PSNH s ES rate has been higher than competitive energy prices offered to some customers. Further increases may occur as the costs associated with the Clean Air Project are fully phased into rates. Customers remaining on PSNH s ES rate may experience an increase in cost due to the lower base over which to recover PSNH's fixed generation costs. Any such increase may in turn cause further migration and further impact PSNH s ES rate. 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.

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 $222 million in 2012 and expect to make an approximate $285 million contribution in 2013. 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 commercial paper program, 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 repay borrowings from NU parent, and/or NU parent s ability to access its commercial paper program 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 NSTAR Electric), and obligations to trade creditors. Additionally, the Regulated companies could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from NU parent. Should the Regulated companies not be able to pay dividends or repay funds due to NU parent, or if NU parent cannot access its commercial paper programs 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.

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, 2012, NU and our electric operating subsidiaries owned the following:

NU	**Electric Distribution**	**Electric Transmission**
Number of substations owned	557	60
Transformer capacity (in kVa)	41,504,000	17,827,000
Overhead lines (distribution in pole miles and transmission in circuit miles)	51,988	3,835
Capacity range of overhead transmission lines (in kV)		69 to 345
Underground lines (distribution in conduit bank miles and transmission in cable miles)	12,656	677
Capacity range of underground transmission lines (in kV)		69 to 345

	CL&P		**NSTAR Electric**		**PSNH**		**WMECO**	
	Distribution	**Transmission**	**Distribution**	**Transmission**	**Distribution**	**Transmission**	**Distribution**	**Transm**
Number of substations owned	212	19	138	20	163	13	44	
Transformer capacity (in kVa)	18,487,000	3,117,000	11,374,000	9,575,000	7,626,000	3,868,000	4,017,000	1,26
Overhead lines (distribution in pole miles and transmission in circuit miles)	18,375	1,625	16,570	708	13,253	1,010	3,790	
Capacity range of overhead								

transmission lines (in kV)		69 to 345		115 to 345		115 to 345		69 t
Underground lines (distribution in conduit bank miles and transmission in cable miles)	1,154	403	9,508	243	1,704	1	290	
Capacity range of underground transmission lines (in kV)		69 to 345		115 to 345		115		

	NU	CL&P	NSTAR Electric	PSNH	WMECO
Underground and overhead line transformers in service	683,514	337,727	130,787	167,523	47,477
Aggregate capacity (in kVa)	49,357,003	28,398,407	10,111,403	6,995,487	3,851,706

Electric Generating Plants

As of December 31, 2012, 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	935,343
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		1,148,800

*

Claimed capability represents winter ratings as of December 31, 2012. The combined nameplate capacity of the generating plants is approximately 1,200 MW.

As of December 31, 2012, 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 2012.

Natural Gas Distribution System

As of December 31, 2012, Yankee Gas owned 28 active gate stations, 203 district regulator stations, and 3,265 miles of natural gas main pipeline. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut.

As of December 31, 2012, NSTAR Gas owned 21 active gate stations, 145 district regulator stations, and 3,185 miles of natural gas main pipeline. NSTAR Gas and Hopkinton own a satellite vaporization plant and above ground cryogenic storage tanks. In addition, Hopkinton owns a liquefaction and vaporization plant. Combined, the tanks have an aggregate storage capacity equivalent to 3.5 Bcf of natural gas.

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 under Connecticut law 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. Connecticut law prohibits an electric distribution company from owning or operating generation assets. However, under "An Act Concerning Energy Independence," enacted in 2005, CL&P is permitted 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, under "An Act Concerning Electricity and Energy Efficiency," enacted in 2007, an electric distribution company, such as CL&P, is permitted to purchase an existing electric generating plant located in Connecticut that is offered for sale, subject to prior approval from the PURA and a determination by the PURA that such purchase is in the public interest. Finally, Connecticut law also 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.

NSTAR ELECTRIC AND NSTAR GAS. Through their charters, which are unlimited in time, NSTAR Electric and NSTAR Gas have the right to engage in the business of delivering and selling electricity and natural gas within their respective service territories, and have powers incidental thereto and are entitled to all the rights and privileges of and subject to the duties imposed upon electric and natural gas companies under Massachusetts laws. The locations in public ways for electric transmission and distribution lines and gas distribution pipelines are obtained from municipal and other state authorities who, in granting these locations, act as agents for the state. In some cases the actions of these authorities are subject to appeal to the DPU. The rights to these locations are not limited in time and are subject to the action of these authorities and the legislature. Under Massachusetts law, with the exception of municipal-owned utilities, no other entity may provide electric or gas delivery service to retail customers within NSTAR s service territory without the written consent of NSTAR Electric and/or NSTAR Gas. This consent must be filed with the DPU and the municipality so affected.

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 NSTAR Electric. 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.

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.

PSNH is also subject to certain regulatory oversight by the Maine Public Utilities Commission and the Vermont Public Service Board.

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

25

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 applicable to NSTAR Electric (described above) is also applicable to WMECO.

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.

Yankee Companies v. U.S. Department of Energy

In 1998, the Yankee Companies (CYAPC, YAEC and MYAPC) filed separate complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE (DOE Phase I Damages). 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. On May 18, 2012, the U.S. Court of Appeals for the Federal Circuit issued a unanimous panel decision in favor of the Yankee Companies upholding the trial court's awards to each company in the remanded cases, and increasing YAEC damages by approximately $17 million to cover certain wet pool operating expenses. On August 1, 2012, the DOE filed a petition asking the U.S. Court of Appeals for the Federal Circuit to reconsider its unanimous panel decision in favor of the Yankee Companies upholding the trial court's awards to each company in the remanded cases. On September 5, 2012, the U.S. Court of Appeals for the Federal Circuit denied the DOE s petition. The decisions became final and non-appealable and interest on the judgments began to accrue on or about December 5, 2012, as the DOE elected not to file a petition for certiorari with the U.S. Supreme Court. In late January 2013, the proceeds from the DOE Phase 1 Damages claim were received by CYAPC, in the amount of $39.6 million; YAEC, in the amount of $38.3 million; and MYAPC, in the amount of $81.7 million. The funds were transferred to each Yankee Company s respective decommissioning trust. The final application of the proceeds for the benefit of customers of CL&P, NSTAR Electric, PSNH and WMECO will be determined following rate proceedings to be filed by the Yankee Companies at FERC in the second quarter of 2013. Final FERC determinations are expected by the end of the third quarter of 2013.

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 related to the alleged failure of the DOE to provide for a permanent facility to store spent nuclear fuel generated in years after 2001 for CYAPC and YAEC and after 2002 for MYAPC (DOE Phase II Damages). 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 record is now closed, all post-trial briefing has been completed, and the case is awaiting the court decision.

The methodology for applying any DOE Phase II Damages that may be recovered from the DOE for the benefit of customers of CL&P, NSTAR Electric, PSNH and WMECO will be addressed in the same FERC rate proceedings.

2.

<u>Conservation Law Foundation v. PSNH</u>

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, 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 N.H. Air Resources Council, and the N.H. Site Evaluation Committee, all of which have been denied. PSNH believes this suit is without merit and intends to defend it vigorously. On

September 27, 2012, the federal court dismissed portions of CLF s suit pertaining to the installation of activated carbon injection and the electrostatic precipitators. An additional motion to dismiss the remaining counts is still pending.

3.

Other Legal Proceedings

For further discussion of legal proceedings, see Item 1, *Business:* "- Electric Distribution Segment," "- Natural Gas Distribution Segment" and "- Electric Transmission Segment," 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, electric and magnetic fields, 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, 2013. 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	43	Vice President, Controller and Chief Accounting Officer.
Gregory B. Butler	55	Senior Vice President, General Counsel and Secretary.
Christine M. Carmody*	50	Senior Vice President-Human Resources of NUSCO and NSTAR Electric & Gas.
James J. Judge	57	Executive Vice President and Chief Financial Officer.
Thomas J. May	65	President and Chief Executive Officer.
David R. McHale	52	Executive Vice President and Chief Administrative Officer.
Joseph R. Nolan, Jr.*	49	Senior Vice President-Corporate Relations of NUSCO and NSTAR Electric & Gas.
Leon J. Olivier	64	Executive Vice President and Chief Operating Officer.

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

Jay S. Buth. Mr. Buth became Vice President, Controller and Chief Accounting Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas, NUSCO and NSTAR Electric & Gas upon completion of the Merger. Previously, Mr. Buth was Vice President-Accounting and Controller of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from June 2009 through the completion of the Merger. From June 2006 through January 2009, Mr. Buth was the Vice President and Controller for New Jersey Resources Corporation, an energy services holding company that provides natural gas and wholesale energy services, including transportation, distribution and asset management.

Gregory B. Butler. Mr. Butler became Senior Vice President, General Counsel and Secretary of NU and Senior Vice President and General Counsel of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas upon completion of the Merger. He has served as Senior Vice President and General Counsel of CL&P, PSNH, WMECO, Yankee Gas and NUSCO since March 9, 2006. Mr. Butler was elected a Director of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas upon completion of the Merger. He has served as a Director of NUSCO since November 27, 2012, and of CL&P, PSNH, WMECO and Yankee Gas since April 22, 2009. Previously Mr. Butler served as Senior Vice President and General Counsel of NU from December 1, 2005 to April 2012. Mr. Butler became a Trustee of the NSTAR Foundation effective upon completion of the Merger. He has served as a Director of Northeast Utilities Foundation, Inc. since December 1, 2002.

Christine M. Carmody. Ms. Carmody became Senior Vice President-Human Resources of NUSCO upon completion of the Merger and of CL&P, PSNH, WMECO and Yankee Gas effective November 27, 2012. She has served as Senior Vice President-Human Resources of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas since August 1, 2008. Ms. Carmody was elected a Director of CL&P, PSNH, WMECO and Yankee Gas upon completion of the Merger, and of NSTAR Electric, NSTAR Gas, NUSCO and NSTAR Electric & Gas effective November 27, 2012. Previously, Ms. Carmody served as Vice President-Organizational Effectiveness of NSTAR, NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas from June 2006 to August 2008. Ms. Carmody became a Director of Northeast Utilities Foundation, Inc. effective upon completion of the Merger. She has served as a Trustee of the NSTAR Foundation since August 1, 2008.

James J. Judge. Mr. Judge became Executive Vice President and Chief Financial Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas, NUSCO and NSTAR Electric & Gas upon completion of the Merger. Mr. Judge was elected a Director of CL&P, PSNH, WMECO, Yankee Gas and NUSCO upon completion of the Merger. He has served as a Director of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas since September 27, 1999. Previously, Mr. Judge served as Senior Vice President and Chief Financial Officer of NSTAR, NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas from 1999 until April 2012. Mr. Judge became Treasurer and a Director of Northeast Utilities Foundation, Inc. effective upon completion of the Merger. He has served as a Trustee of the NSTAR Foundation since December 12, 1995.

Thomas J. May. Mr. May became President and Chief Executive Officer and a Trustee of NU, Chairman and a Director of CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas, and Chairman, President and

Chief Executive Officer and a Director

of NUSCO upon completion of the Merger. He has been President and Chief Executive Officer of NSTAR Electric & Gas since January 1, 2002. Mr. May has served as a Director of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas (or their predecessor companies) since September 27, 1999. Previously, Mr. May served as Chairman, President and Chief Executive Officer and a Trustee of NSTAR, and as Chairman, President and Chief Executive Officer of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas until the closing of the Merger. He served as Chairman, Chief Executive Officer and a Trustee since NSTAR was formed in 1999, and was elected President in 2002. Mr. May became a Director of Northeast Utilities Foundation, Inc. upon completion of the Merger. He has served as a Trustee of the NSTAR Foundation since August 18, 1987.

David R. McHale. Mr. McHale became Executive Vice President and Chief Administrative Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas, NUSCO and NSTAR Electric & Gas upon completion of the Merger. Mr. McHale has served as a Director of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas since November 27, 2012, of PSNH, WMECO, Yankee Gas and NUSCO since January 1, 2005, and of CL&P since January 15, 2007. Previously, Mr. McHale served as Executive Vice President and Chief Financial Officer of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from January 2009 to April 2012, and Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from January 2005 to December 2008. Mr. McHale became a Trustee of the NSTAR Foundation upon completion of the Merger. He has served as a Director of Northeast Utilities Foundation, Inc. since January 1, 2005.

Joseph R. Nolan, Jr. Mr. Nolan became Senior Vice President-Corporate Relations of NUSCO, NSTAR Electric & Gas, NSTAR Electric and NSTAR Gas upon completion of the Merger. He became Senior Vice President-Corporate Relations of CL&P, PSNH, WMECO and Yankee Gas effective November 27, 2012. Mr. Nolan was elected a Director of CL&P, PSNH, WMECO and Yankee Gas upon completion of the Merger, and of NSTAR Electric, NSTAR Gas, NUSCO and NSTAR Electric & Gas effective November 27, 2012. Previously, Mr. Nolan served as Senior Vice President-Customer & Corporate Relations of NSTAR, NSTAR Electric, NSTAR Gas and NSTAR Electric and Gas from 2006 until the closing of the Merger. Mr. Nolan became a Director of Northeast Utilities Foundation, Inc. upon completion of the Merger. He has served as a Trustee of the NSTAR Foundation since October 1, 2000.

Leon J. Olivier. Mr. Olivier has served as Executive Vice President and Chief Operating Officer of NU and NUSCO since May 13, 2008, and of NSTAR Electric & Gas since the completion of the Merger. He became Chief Executive Officer of NSTAR Electric and NSTAR Gas upon completion of the Merger. Mr. Olivier has served as Chief Executive Officer of CL&P, PSNH, WMECO and Yankee Gas since January 15, 2007. Mr. Olivier was elected a Director of NSTAR Electric, NSTAR Gas and NSTAR Electric & Gas effective November 27, 2012, of PSNH, WMECO and Yankee Gas effective January 17, 2005, and of CL&P effective September 10, 2001. Previously, Mr. Olivier served as Executive Vice President-Operations of NU from February 13, 2007 to May 12, 2008. Mr. Olivier became a Trustee of the NSTAR Foundation upon completion of the Merger. He has served as a Director of Northeast Utilities Foundation, Inc. since April 1, 2006.

Item 4.

Mine Safety Disclosures

Not applicable.

PART II

Item 5.

Market for the Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

(a)

Market Information and (c) Dividends

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 of our common shares and the dividends declared, for the past two years, by quarter, are shown below.

Year	Quarter	High	Low	Dividends Declared
2012	First	$ 37.64	$ 33.48	$ 0.294
	Second	39.09	34.84	0.343
	Third	40.86	36.68	0.343
	Fourth	40.38	37.53	0.343
2011	First	$ 35.13	$ 31.19	$ 0.275
	Second	36.47	33.31	0.275
	Third	35.87	30.02	0.275
	Fourth	36.40	30.80	0.275

Information with respect to dividend restrictions for us, CL&P, NSTAR Electric, 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, NSTAR Electric, PSNH and WMECO. All of the common stock of CL&P, NSTAR Electric, PSNH and WMECO is held solely by NU.

During 2012 and 2011, CL&P approved and paid $100.5 million and $243.2 million, respectively, of common stock dividends to NU.

Since April 10, 2012, NSTAR Electric approved and paid $159.9 million of common stock dividends to NSTAR LLC.

During 2012 and 2011, PSNH approved and paid $90.7 million and $58.8 million, respectively, of common stock dividends to NU.

During 2012 and 2011, WMECO approved and paid $9.4 million and $26.3 million, respectively, of common stock dividends to NU.

(b)

Holders

As of January 31, 2013, there were 49,487 registered common shareholders of our company on record. As of the same date, there were a total of 332,767,098 common shares issued.

(c)

Securities Authorized for Issuance Under Equity Compensation Plans

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.

(d)

Performance Graph

As allowed under Exchange Act Rule 14c-3 (17 CFR 240.14c-3), we provide the five-year cumulative performance graph annually, accompanying our Definitive Proxy Statement pursuant to section 14(a) of the Securities Exchange Act of 1934.

(e)

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table discloses purchases of shares of our common stock made by us or on our behalf for the periods shown below.

Period	**Total Number of Shares Purchased**		**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)**
October 1 - October 31, 2012	714,846	$	39.53	-	-
November 1 - November 30, 2012	21,159		38.48	-	-
December 1 - December 31, 2012	258,263		38.98	-	-
Total	994,268	$	39.37	-	-

Item 6. **Selected Consolidated Financial Data**

NU Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and common share information)	**2012 (a)**	**2011**	**2010**	**2009**	**2008**
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 16,605,010	$ 10,403,065	$ 9,567,726	$ 8,839,965	$ 8,207,876
Total Assets	28,302,824	15,647,066	14,472,601	14,057,679	13,988,480
Total Capitalization (b)	17,356,112	9,078,321	8,627,985	8,253,323	7,293,960
Obligations Under Capital Leases (b)	11,071	12,358	12,236	12,873	13,397
Income Statement Data:					
Operating Revenues	$ 6,273,787	$ 4,465,657	$ 4,898,167	$ 5,439,430	$ 5,800,095
Net Income	533,077	400,513	394,107	335,592	266,387
Net Income Attributable to Noncontrolling Interests	7,132	5,820	6,158	5,559	5,559
Net Income Attributable to Controlling Interest	$ 525,945	$ 394,693	$ 387,949	$ 330,033	$ 260,828
Common Share Data:					
Basic Earnings Per Common Share:					
Net Income Attributable to Controlling	$ 1.90	$ 2.22	$ 2.20	$ 1.91	$ 1.68

Interest										
Diluted Earnings Per Common Share:										
Net Income Attributable to Controlling Interest	$	1.89	$	2.22	$	2.19	$	1.91	$	1.67
Weighted Average Common Shares Outstanding:										
Basic		277,209,819		177,410,167		176,636,086		172,567,928		155,531,846
Diluted		277,993,631		177,804,568		176,885,387		172,717,246		155,999,240
Dividends Declared Per Common Share	$	1.32	$	1.10	$	1.03	$	0.95	$	0.83
Market Price - Closing (high) (c)	$	40.57	$	36.31	$	32.05	$	26.33	$	31.15
Market Price - Closing (low) (c)	$	33.53	$	30.46	$	24.78	$	19.45	$	19.15
Market Price - Closing (end of year) (c)	$	39.08	$	36.07	$	31.88	$	25.79	$	24.06
Book Value Per Share (end of year)	$	29.41	$	22.65	$	21.60	$	20.37	$	19.38
Tangible Book Value Per Share (end of year) (d)	$	18.21	$	21.03	$	19.97	$	18.74	$	17.54
Rate of Return Earned on Average Common Equity (%) (e)		7.9		10.1		10.7		10.2		8.8
Market-to-Book Ratio (end of year) (f)		1.3		1.6		1.5		1.3		1.2
Capitalization:										
Total Equity		53 %		44 %		44 %		44 %		41 %
Preferred Stock, not subject to mandatory redemption		1		1		1		1		2
Long-Term Debt (b)		46		55		55		55		57
		100 %		100 %		100 %		100 %		100 %

(a) The 2012 results include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012.

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

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

(d) Common Shareholders' Equity adjusted for goodwill and intangibles divided by total common shares outstanding.

(e) Net Income Attributable to Controlling Interest divided by average Common Shareholders' Equity.

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

CL&P Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	**2012**		**2011**		**2010**		**2009**		**2008**
Operating Revenues $	2,407,449	$	2,548,387	$	2,999,102	$	3,424,538	$	3,558,361
Net Income	209,725		250,164		244,143		216,316		191,158
Cash Dividends on Common Stock	100,486		243,218		217,691		113,848		106,461
Property, Plant and Equipment, Net	6,152,959		5,827,384		5,586,504		5,340,561		5,089,124
Total Assets	9,142,088		8,791,396		8,255,192		8,364,564		8,336,118
Rate Reduction Bonds	-		-		-		195,587		378,195
Long-Term Debt (a)	2,862,790		2,583,753		2,583,102		2,582,361		2,270,414
Preferred Stock Not Subject to Mandatory Redemption	116,200		116,200		116,200		116,200		116,200
Obligations Under Capital Leases (a)	9,960		10,715		10,613		10,956		11,207

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

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.

NU Selected Consolidated Sales Statistics	**2012 [(a)]**	**2011**	**2010**	**2009**	**2008**
Revenues: *(Thousands)*					
Residential	$ 2,731,951	$ 2,091,270	$ 2,336,078	$ 2,569,278	$ 2,525,635
Commercial	1,563,709	1,201,091	1,303,841	1,462,786	1,607,224
Industrial	753,974	252,878	268,598	297,854	399,753
Wholesale	357,223	350,413	506,475	445,261	545,127
Streetlighting and Railroads	40,952	35,283	42,387	33,035	38,522
Miscellaneous and Eliminations	130,137	47,485	(29,878)	128,118	24,673
Total Electric	5,577,946	3,978,420	4,427,501	4,936,332	5,140,934
Natural Gas	572,857	430,799	434,277	449,571	577,390
Total - Regulated Companies	6,150,803	4,409,219	4,861,778	5,385,903	5,718,324
Other and Eliminations	122,984	56,438	36,389	53,527	81,771
Total	$ 6,273,787	$ 4,465,657	$ 4,898,167	$ 5,439,430	$ 5,800,095
Regulated Companies - Sales: *(GWh)*					
Residential	19,719	14,766	14,913	14,412	14,509
Commercial	24,117	14,301	14,506	14,474	14,885
Industrial	5,462	4,418	4,481	4,423	5,149
Wholesale	2,154	1,020	3,423	4,183	3,576
Streetlighting and Railroads	420	327	330	336	340
Total	51,872	34,832	37,653	37,828	38,459
Regulated Companies - Customers: *(Average)*					
Residential	2,711,407	1,710,342	1,704,197	1,696,756	1,700,207
Commercial	355,385	193,505	192,266	189,265	190,067
Industrial	8,279	7,083	7,150	7,207	7,342
Streetlighting, Railroads and Wholesale	15,004	5,735	6,292	7,548	4,605

Total Electric	3,090,075	1,916,665	1,909,905	1,900,776	1,902,221
Natural Gas	483,770	207,753	205,885	206,438	204,834
Total	3,573,845	2,124,418	2,115,790	2,107,214	2,107,055

(a) The 2012 results include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012.

CL&P Selected Consolidated Sales Statistics

	2012	2011	2010	2009	2008
Revenues: *(Thousands)*					
Residential	$ 1,263,845	$ 1,345,290	$ 1,597,754	$ 1,840,750	$ 1,811,845
Commercial	711,337	732,968	821,872	935,586	1,042,077
Industrial	126,165	126,783	144,463	151,839	190,723
Wholesale	214,807	278,751	441,660	386,034	484,843
Streetlighting and Railroads	21,283	25,177	32,084	22,638	28,710
Miscellaneous	70,012	39,418	(38,731)	87,691	163
Total	$ 2,407,449	$ 2,548,387	$ 2,999,102	$ 3,424,538	$ 3,558,361
Sales: *(GWh)*					
Residential	9,978	10,092	10,196	9,848	9,913
Commercial	9,414	9,525	9,716	9,705	9,993
Industrial	2,426	2,414	2,467	2,427	2,945
Wholesale	1,155	1,592	3,040	3,434	3,637
Streetlighting and Railroads	291	284	286	286	294
Total	23,264	23,907	25,705	25,700	26,782
Customers: *(Average)*					
Residential	1,103,397	1,100,740	1,096,576	1,093,229	1,094,991
Commercial	104,323	103,975	103,166	101,814	102,464
Industrial	3,301	3,331	3,359	3,381	3,613
Streetlighting, Railroads and Wholesale	4,266	4,260	4,366	5,307	2,883
Total	1,215,287	1,212,306	1,207,467	1,203,731	1,203,951

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 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 Interest of each business by the weighted average diluted NU common shares outstanding for the period. The discussion below also includes non-GAAP financial measures referencing our 2012, 2011, and 2010 earnings and EPS excluding certain impacts related to NU's merger with NSTAR, a 2011 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, and certain non-recurring benefits from the settlement of tax issues in 2010. We use these non-GAAP financial measures to evaluate and to provide details of earnings results by business and to more fully compare and explain our 2012, 2011 and 2010 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 Interest, we believe that the non-GAAP presentation is more representative of our financial performance and provides additional and useful information to readers of this report in analyzing historical and future performance by business. These non-GAAP financial measures should not be considered as an alternative to reported Net Income Attributable to Controlling Interest or EPS determined in accordance with GAAP as an indicator 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 Interest are included under "Financial Condition and Business Analysis Overview Consolidated" in *Management's Discussion and Analysis*, herein.

Financial Condition and Business Analysis

Merger with NSTAR:

On April 10, 2012, NU and NSTAR completed our merger. Pursuant to the terms and conditions of the Agreement and Plan of Merger, as amended (the Merger Agreement), NSTAR merged into NSTAR LLC, becoming a wholly-owned subsidiary of NU. Unless otherwise noted, the results of NSTAR LLC and its subsidiaries, hereinafter referred to as "NSTAR," are included from the date of merger, April 10, 2012, through December 31, 2012 throughout this *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

The transaction was structured as a merger of equals in a tax-free exchange of shares. Pursuant to the Merger Agreement, NU issued to NSTAR shareholders 1.312 NU common shares for each issued and outstanding NSTAR common share. As a result, NU issued approximately 136 million common shares to the NSTAR shareholders.

Executive Summary

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

Results and Outlook:

.

We earned $525.9 million, or $1.89 per share, in 2012, compared with $394.7 million, or $2.22 per share, in 2011. Excluding after-tax merger-related costs of $107.6 million, or $0.39 per share, we earned $633.5 million, or $2.28 per share, in 2012. Excluding after-tax 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 2011 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 earnings results in 2012 were due primarily to the inclusion of NSTAR effective April 10, 2012 as well as higher transmission segment earnings as a result of increased investments in the transmission infrastructure.

.

The addition of NSTAR effective April 10, 2012 provided an earnings contribution of $182.9 million in 2012. Due to the timing of the merger closing, NSTAR results for the first three months of 2012 are not reflected in NU s 2012 results.

.

Our transmission segment earned $249.7 million, or $0.90 per share, in 2012, compared with $199.6 million, or $1.12 per share, in 2011.

.

Our electric distribution segment, which includes generation, earned $292.3 million, or $1.04 per share, in 2012, compared with $189.1 million, or $1.06 per share, in 2011. The 2012 results include $51.1 million, or $0.19 per share, of after-tax merger settlement agreement costs and the 2011 results include the CL&P storm fund reserve.

.

Our natural gas distribution segment earned $30.8 million, or $0.11 per share, in 2012, compared with $31.7 million, or $0.18 per share, in 2011. The 2012 results include $2.1 million, or $0.01 per share, of after-tax merger settlement agreement costs.

.

NU parent and other companies recorded net losses of $46.9 million, or $0.16 per share, in 2012, compared with net losses of $25.7 million, or $0.14 per share, in 2011. The 2012 and 2011 results include $54.4 million, or $0.19 per share, and $11.3 million, or $0.06 per share, respectively, of after-tax merger costs.

.

We project capital expenditures of approximately $5 billion from 2013 through 2015. Of the $5 billion, we expect to invest approximately $2.5 billion in our electric and natural gas distribution segments, and $2.3 billion in our electric transmission segment. In addition, we project capital expenditures of approximately $1.6 billion from 2016 through 2017 in our electric transmission segment.

Legislative, Regulatory, Policy and Other Items:

.

On June 15, 2012, Connecticut enacted the "Enhancing Emergency Preparedness and Response Act," which is intended to enhance the state s emergency preparedness and response in the event of natural disasters. Among numerous provisions, the bill required the PURA to establish emergency performance standards for utilities and allows the PURA to levy penalties for failure to meet those standards.

.

On August 1, 2012, efforts to settle a complaint filed at FERC by various New England parties concerning the base ROE earned by New England transmission owners ended without a settlement. Soon thereafter, litigation began before a FERC trial judge. In the fourth quarter of 2012, additional testimony and complaints were filed. On January

18, 2013, the FERC trial staff filed testimony and analysis recommending a base ROE of 9.66 percent based on the midpoint of their analysis with a range of reasonableness of 6.82 percent to 12.51 percent. Hearings are scheduled for May 2013, a trial judge s ruling is due in September 2013, and a FERC decision is expected in 2014.

.

On August 1, 2012, PURA issued a final decision in the investigation of CL&P s performance related to both Tropical Storm Irene and the October 2011 snowstorm. The decision concluded that CL&P was deficient and inadequate in its preparation, response, and communication to both storms, and identified certain penalties that could be imposed on CL&P during its next rate case. However, PURA will consider and weigh the extent to which CL&P has taken steps to improve current practices in future storm response in determining any potential penalties. We believe such steps to improve current storm preparation and response practices have been successfully executed in recent storms, and that CL&P's response to these 2011 storms was prudent and consistent with industry standards, and that it is probable that it will be able to recover its deferred costs.

.

On August 3, 2012, Massachusetts Governor Patrick signed into law "An Act Relative to Competitively Priced Electricity in the Commonwealth." The Act establishes distribution rate case requirements for both electric and natural gas utility companies, as well as limiting settlement agreements, establishes new timing on rate case proceedings, and establishes requirements for all distribution companies to enter into additional long-term renewable energy distribution contracts.

.

On August 6, 2012, Massachusetts Governor Patrick signed into law "An Act relative to emergency service response of public utility companies" to help improve utility companies emergency response and communication, as well as indicate how any assessed penalties will be provided to customers.

.

On October 29, 2012, Hurricane Sandy caused extensive damage to our electric distribution system across all three states resulting in deferred storm restoration costs of $204 million. Approximately 1.5 million of our 3.1 million electric distribution customers were without power during or following the storm. We believe the storm restoration costs meet the criteria for specific cost recovery in each state in which we operate and, as a result, we do not expect the storm to have a material impact on our results of operations.

.

On December 11, 2012, in separate orders issued by the DPU, NSTAR Electric and WMECO received penalties of $4.1 million and $2 million, respectively, related to the investigation into the electric utilities responses to Tropical

Storm Irene and the October 2011 snowstorm. The DPU stated that NSTAR Electric failed to communicate and prioritize restoration efforts in both storms and WMECO failed to prioritize restoration efforts in the October snowstorm. On December 28, 2012, NSTAR Electric and WMECO each filed appeals arguing the DPU penalties should be vacated. While we believe NSTAR Electric and WMECO should ultimately prevail upon appeal, we are unable to conclusively state that a favorable outcome is probable.

.

On January 16, 2013, PURA approved the $300 million plan CL&P filed on July 9, 2012 to improve the resiliency of the CL&P electric distribution system. The plan is consistent with the terms of the Connecticut settlement agreement among NU, NSTAR, and various Connecticut state agencies.

.

On February 8, 2013, a blizzard caused damage to the electric delivery systems of CL&P and NSTAR Electric. We have estimated that approximately 71,000 and 350,000 of CL&P and NSTAR Electric's distribution customers, respectively, were without power during or following the storm. We believe that this storm will cost between $100 million to $120 million, with approximately 90 percent of those costs relating to NSTAR Electric. We expect the storm restoration costs to meet the criteria for specific cost recovery in each state in which we operate and, as a result, we do not expect the storm to have a material impact on our results of operations.

.

On February 19, 2013, Connecticut issued a final comprehensive energy strategy (strategy). The strategy includes a series of policy proposals that aim to expand energy choices, including natural gas, improve environmental conditions, create clean energy jobs, and enhance the quality of life for customers in the state. Many of the recommendations in the strategy will require actions by the PURA and potentially the legislature.

.

NPT has identified a new route in the northern-most part of the project s route where PSNH did not own any rights of way. We expect to file the new route with the DOE in the first quarter of 2013, and we believe that NPT will be completed in early 2017. We estimate the costs of the Northern Pass transmission project will be approximately $1.2 billion.

Liquidity:

.

Cash and cash equivalents totaled $45.7 million as of December 31, 2012, compared with $6.6 million as of December 31, 2011, while cash capital expenditures totaled $1.5 billion in 2012, compared with $1.1 billion in 2011.

.

Cash flows provided by operating activities in 2012 totaled $1.05 billion, compared with operating cash flows of $901.1 million in 2011 (amounts are net of RRB payments). The improved cash flows were due primarily to the addition of NSTAR, which contributed $450.8 million of operating cash flows (net of RRB payments) to NU since the date of the merger, April 10, 2012. Offsetting the favorable NSTAR cash flow impact was an increase in storm restoration costs, NUSCO Pension Plan cash contributions, 2012 customer bill credits and NU Parent merger transaction cost payments.

.

In 2012, we issued $850 million of new long-term debt consisting of $400 million by NSTAR Electric, $300 million by NU Parent, and $150 million by WMECO. These new issuances were used primarily to repay $716.8 million of existing long-term debt, of which $663 million matured in 2012 ($400 million at NSTAR Electric and $263 million at NU Parent) and WMECO s tax-exempt PCRBs of $53.8 million scheduled to mature in 2028. Additionally, CL&P remarketed $62 million of tax-exempt PCRBs in April 2012 and redeemed $116.4 million of tax-exempt PCRBs in October 2012. As of December 31, 2012, approximately $730 million of NU's current liabilities relate to long-term debt that will be paid in the next 12 months.

.

On March 26, 2012, CL&P entered into a five-year $300 million unsecured revolving credit facility. The credit facility is intended to finance short-term borrowings that CL&P incurred to fund costs of restoring power following Tropical Storm Irene and the October 2011 snowstorm. As of December 31, 2012, CL&P had $89 million in borrowings outstanding under this credit facility.

.

On July 25, 2012, NU and certain of its subsidiaries jointly entered into a five-year $1.15 billion revolving credit facility, and NSTAR Electric entered into a five-year $450 million revolving credit facility. The new facilities expire on July 25, 2017 and will be used primarily to backstop NU s $1.15 billion commercial paper program and NSTAR Electric s $450 million commercial paper program. As of December 31, 2012, NU and NSTAR Electric had $1.15 billion and $276 million in borrowings outstanding under their respective commercial paper programs.

.

On January 15, 2013, CL&P issued $400 million of 2.5 percent first mortgage bonds that will mature on January 15, 2023. The proceeds, net of issuance costs, were used to repay CL&P s revolving credit facility borrowings of $89 million and $305.8 million of its commercial paper program borrowings.

.

On February 5, 2013, our Board of Trustees approved a common dividend payment of $0.3675 per share, payable March 28, 2013 to shareholders of record as of March 1, 2013. The dividend represented an increase of 7.1 percent over the $0.343 per share quarterly dividend paid in December 2012.

Overview

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 Interest and diluted EPS, for 2012, 2011 and 2010 is as follows:

	For the Years Ended December 31,					
	2012 (1)		2011		2010	
(Millions of Dollars, Except Per Share Amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income Attributable to Controlling Interest (GAAP)	$ 525.9	$ 1.89	$ 394.7	$ 2.22	$ 387.9	$ 2.19
Regulated Companies	$ 626.0	$ 2.25	$ 438.3	$ 2.46	$ 384.0	$ 2.16
NU Parent and Other Companies	7.5	0.03	(14.4)	(0.08)	(2.4)	(0.00)
Non-GAAP Earnings	633.5	2.28	423.9	2.38	381.6	2.16
Merger and Related Costs (after-tax)	(107.6)	(0.39)	(11.3)	(0.06)	(9.4)	(0.06)
Storm Fund Reserve	-	-	(17.9)	(0.10)	-	-
Non-Recurring Tax Settlements	-	-	-	-	15.7	0.09
Net Income Attributable to Controlling Interest (GAAP)	$ 525.9	$ 1.89	$ 394.7	$ 2.22	$ 387.9	$ 2.19

(1)

Results include the operations of NSTAR from the date of merger, April 10, 2012, through December 31, 2012.

The after-tax merger and related costs for 2012 consisted of the following charges:

.

Transaction and integration-related costs of $34 million at NU parent related to investment advisory fees, attorney fees, and consulting costs;

.

Change in control costs and other compensation costs of $13.5 million at NU parent and NSTAR;

.

A $23.6 million charge at CL&P related to the Connecticut settlement agreement, pursuant to which CL&P agreed to forego recovery of $40 million (pre-tax) of deferred storm restoration costs associated with Tropical Storm Irene and the October 2011 snowstorm;

.

A $14.8 million charge at CL&P for customer bill credits related to the Connecticut settlement agreement;

.

An aggregate of $12.8 million of charges at NSTAR Electric, NSTAR Gas, and WMECO for customer bill credits related to the Massachusetts settlement agreement; and

.

An $8.9 million charge at NU parent for the establishment of a fund to advance Connecticut energy goals related to the Connecticut settlement agreement.

Excluding the impacts of the 2012 and 2011 merger and related settlement agreement costs and the 2011 storm fund reserve, our 2012 earnings increased by $209.6 million, as compared to 2011, due primarily to the inclusion of NSTAR effective April 10, 2012, and higher transmission segment earnings as a result of increased investments in the transmission infrastructure. On an earnings per share basis, the 2012 NSTAR earnings contribution of $182.9 million ($204.5 million in non-GAAP earnings) was partially offset by the issuance of approximately 136 million common shares to close the merger. Offsetting these favorable earnings impacts were lower retail electric and firm natural gas sales due primarily to significantly milder weather in the first quarter of 2012, compared with the first quarter of 2011, higher pension and healthcare costs, higher depreciation and property taxes.

Regulated Companies: Our Regulated companies consist of the electric distribution, natural gas distribution, and transmission segments. Generation activities of PSNH and WMECO are included in our electric distribution segment. A summary of our segment earnings for 2012, 2011 and 2010 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2012** (1)	**2011**	**2010**
Net Income - Regulated Companies (GAAP)	$ 572.8	$ 420.4	$ 384.0
Electric Distribution	$ 343.4	$ 207.0	$ 173.5
Transmission	249.7	199.6	177.8
Natural Gas Distribution	32.9	31.7	32.7
Net Income - Regulated Companies (Non-GAAP)	626.0	438.3	384.0

Merger Settlement Agreement Costs (after-tax) [2]		(53.2)		-		-
Storm Fund Reserve [3]		-		(17.9)		-
Net Income - Regulated Companies (GAAP)	$	572.8	$	420.4	$	384.0

(1)

Results include NSTAR Electric and NSTAR Gas earnings from the date of merger, April 10, 2012, through December 31, 2012.

(2)

Merger settlement agreement costs are attributable to the electric distribution segment ($51.1 million) and the natural gas distribution segment ($2.1 million).

(3)

The storm fund reserve is attributable to the electric distribution segment.

The higher 2012 transmission segment earnings, as compared to 2011, were due primarily to the inclusion of the NSTAR Electric transmission business and increased investments in the transmission infrastructure, including GSRP, which is under construction in western Massachusetts and northern Connecticut.

Our electric distribution segment earned $292.3 million in 2012, compared with $189.1 million in 2011. Excluding the impacts of the 2012 merger settlement agreement costs and the 2011 storm fund reserve, our electric distribution segment earned $343.4 million in 2012 and $207 million in 2011. The higher earnings were due primarily to the addition of NSTAR Electric. Excluding $10.9 million of after-tax merger settlement agreement costs, which related to customer bill credits, NSTAR Electric s distribution business earned $150.2 million from April 10, 2012 through December 31, 2012. For further information regarding NSTAR Electric s earnings, see "Results of Operations NSTAR Electric Company and Subsidiaries Earnings Summary" in this *Management's Discussion and Analysis of Financial Condition and Results of Operations.* Offsetting this favorable earnings impact was lower retail revenue, which was primarily the result of warmer than normal weather in the first quarter of 2012 as compared to colder than normal weather in the first quarter of 2011. In addition, our electric distribution segment had higher pension and employee benefit costs, higher depreciation and property taxes, and the DPU October snowstorm penalty ($2 million pre-tax) imposed on WMECO in December 2012, partially offset by the favorable impacts of the CL&P and PSNH 2010 distribution rate case decisions. As a result of these decisions, the CL&P rates increased effective July 1, 2011, which resulted in a full year favorable impact to earnings in 2012, while the PSNH rates increased effective July 1, 2012.

Our natural gas distribution segment earned $30.8 million in 2012, compared with $31.7 million in 2011. Excluding the impact of the merger settlement agreement costs, our natural gas distribution segment earned $32.9 million in 2012. The higher earnings were due primarily to the addition of NSTAR Gas results. Excluding $2.1 million of after-tax merger settlement agreement costs, which related to customer bill credits, NSTAR Gas earnings were $6.6 million from April 10, 2012 through December 31, 2012. Offsetting this favorable earnings impact was a decrease in total firm natural gas sales, which was primarily the result of warmer than normal weather in the first quarter of 2012 as compared to colder than normal weather in the first quarter of 2011, and higher pension expense, depreciation and property taxes. These costs were partially offset by lower operations and maintenance costs as well as the favorable impact of the Yankee Gas 2011 rate case decision resulting in the additional increase to annualized rates effective July 1, 2012.

A summary of our retail electric GWh sales and percentage changes, as well as changes in CL&P, NSTAR Electric, PSNH and WMECO retail electric GWh sales, and our firm natural gas sales and percentage changes in million cubic feet, as well as changes in Yankee Gas and NSTAR Gas sales in million cubic feet, for 2012, as compared to 2011, is as follows:

NU Electric	For the Year Ended December 31, 2012 Compared to 2011 Sales (GWh) 2012 [1]	2011	Percentage Increase
Residential	19,719	14,766	33.5%
Commercial	24,117	14,301	68.6%
Industrial	5,462	4,418	23.6%
Other	420	327	28.6%
Total	49,718	33,812	47.0%

	For the Year Ended December 31, 2012 Compared to 2011			
Electric	CL&P Percentage Increase/ (Decrease)	NSTAR Electric [2] Percentage Increase/ (Decrease)	PSNH Percentage Increase/ (Decrease)	WMECO Percentage Increase/ (Decrease)
Residential	(1.1)%	0.2 %	(0.1)%	(1.0)%
Commercial	(1.2)%	(1.7)%	0.0 %	0.7 %
Industrial	0.5 %	(4.6)%	0.7 %	(0.9)%
Other	2.3 %	(12.2)%	(1.0)%	(5.7)%
Total	(0.9)%	(1.4)%	0.1 %	(0.3)%

(1)

NU retail electric sales include the sales of NSTAR Electric from the date of merger, April 10, 2012, through December 31, 2012.

(2)

Results for NSTAR Electric represent its standalone retail electric sales for the year ended December 31, 2012 and 2011.

NU Firm Natural Gas	For the Year Ended December 31, 2012 Compared to 2011 Sales (million cubic feet) 2012 [1]	2011	Percentage Increase
Residential	22,535	13,508	66.8%
Commercial	27,906	17,175	62.5%
Industrial	19,453	16,197	20.1%
Total	69,894	46,880	49.1%
Total, Net of Special Contracts [2]	64,140	38,197	67.9%

	For the Year Ended December 31, 2012 Compared to 2011	
Firm Natural Gas	Yankee Gas Percentage Increase/ (Decrease)	NSTAR Gas [3] Percentage Decrease
Residential	(7.6)%	(10.7)%
Commercial	(3.5)%	(2.9)%
Industrial	(2.5)%	(0.4)%
Total	(4.3)%	(6.2)%
Total, Net of Special Contracts [2]	2.3 %	

(1)

NU firm natural gas sales include the sales of NSTAR Gas from the date of merger, April 10, 2012, through December 31, 2012.

(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.

(3)

NSTAR Gas sales data for the year ended December 31, 2012 compared to 2011 has been provided for comparative purposes only.

Weather and, to a lesser extent, fluctuations in fuel costs, conservation measures, and economic conditions affect sales to our customers. Industrial sales are less sensitive to temperature variations than residential and commercial sales. Weather impacts electric sales primarily during the summer and natural gas sales during the winter in our service territories (natural gas sales are more sensitive to temperature variations than electric sales). Customer heating or cooling usage may not directly correlate with historical levels or with the level of degree-days that occur, particularly when weather patterns experienced are consistently colder or warmer. In addition, our electric and natural gas businesses are sensitive to variations in daily weather, are highly influenced by New England s seasonal weather variations, and are susceptible to damage from major storms and other natural events and disasters that could adversely affect our ability to provide energy.

Our consolidated retail electric and firm natural gas sales were higher in 2012, as compared to 2011, due to the inclusion of NSTAR Electric and NSTAR Gas sales, respectively, from the date of merger, April 10, 2012, through December 31, 2012.

Actual retail electric sales for CL&P, NSTAR Electric and WMECO decreased in 2012, as compared to 2011, due primarily to the warmer than normal weather in the first quarter of 2012, as compared to colder than normal weather in the first quarter of 2011, while actual retail electric sales for PSNH were 0.1 percent higher than last year. In 2012, heating degree days were 11 percent lower in Connecticut and western Massachusetts, 7 percent lower in the Boston metropolitan area, and 9 percent lower in New Hampshire, as compared to 2011. On a weather normalized basis (based on 30-year average temperatures), the average NU combined consolidated total retail electric sales decreased 0.2 percent in 2012, as compared to 2011, assuming NSTAR Electric had been part of the NU combined electric distribution system for all periods under consideration. We believe these decreases were due primarily to increased conservation efforts among all our customer classes and the continued installation of distributed generation at our commercial and industrial customers facilities. 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 annual level of baseline distribution delivery service revenues of $125.4 million that it is able to recover. This effectively breaks the relationship between sales volume and revenues recognized.

Our firm natural gas sales are subject to many of the same influences as our retail electric sales, but have benefitted from lower natural gas prices and customer growth across all three customer classes. In 2012, excluding the impact of NSTAR Gas sales, actual sales decreased, as compared to 2011, due primarily to the warmer than normal weather in the first quarter of 2012, as compared to colder than normal weather in the first quarter of 2011. On a weather normalized basis, Yankee Gas 2012 sales increased due primarily to customer growth, lower cost of natural gas, the migration of interruptible customers switching to firm service rates, and the addition of gas-fired distributed generation in Yankee Gas service territory.

On a weather-normalized basis, the average NU combined consolidated total firm natural gas sales increased 2.7 percent in 2012, as compared to 2011, assuming NSTAR Gas had been part of the NU combined natural gas distribution system for all periods under consideration.

37

NU Parent and Other Companies: NU parent and other companies (which includes our competitive businesses held by NU Enterprises and, from April 10, 2012, NSTAR LLC) recorded net losses of $46.9 million in 2012, compared with net losses of $25.7 million in 2011. Excluding the impact of the 2012 and 2011 merger and related settlement agreement costs, NU parent and other companies recorded earnings of $7.5 million and net losses of $14.4 million, respectively. The NU parent merger and related settlement agreement costs primarily included fees paid to investment advisors and attorneys, a charge for the establishment of a fund to advance Connecticut energy goals related to the Connecticut settlement agreement, and change in control costs and other compensation costs. Excluding merger and related settlement agreement costs, improved results were due primarily to lower interest expense, a lower effective tax rate and the inclusion of NSTAR Communications.

Major Storm Restoration Costs: A storm must meet certain criteria specific to each state and utility company to be declared a major storm. Once a storm is declared major, all qualifying expenses incurred during storm restoration efforts, if deemed prudent, are deferred and recovered from customers in future periods. In Connecticut, qualifying storm restoration costs must exceed $5 million for a storm to be declared as a major storm. In Massachusetts, qualifying storm costs must exceed $1 million for NSTAR Electric and $300,000 for WMECO and an emergency response plan must be initiated for a storm to be declared a major storm. In New Hampshire, (1) at least 10 percent of customers must be without power with at least 200 concurrent locations requiring repairs (trouble spots), or (2) at least 300 concurrent trouble spots must be reported for a storm to be declared a major storm.

On October 29, 2012, Hurricane Sandy caused extensive damage to our electric distribution system across all three states resulting in deferred storm restoration costs of $204 million ($159.9 million for CL&P, $27.8 million for NSTAR Electric, $12.1 million for PSNH, and $4.2 million for WMECO). Approximately 1.5 million of our 3.1 million electric distribution customers were without power during or following the storm, with approximately 850,000 of those customers in Connecticut, approximately 472,000 in Massachusetts, and approximately 137,000 in New Hampshire. We expect the storm restoration costs to meet the criteria for specific cost recovery in Connecticut, Massachusetts, and New Hampshire and, as a result, we do not expect the storm to have a material impact on the results of operations of CL&P, NSTAR Electric, PSNH or WMECO. Each operating company will seek recovery of these deferred storm restoration costs through its applicable regulatory recovery process.

Liquidity

Consolidated: Cash and cash equivalents totaled $45.7 million as of December 31, 2012, compared with $6.6 million as of December 31, 2011.

On March 22, 2012, NU parent issued $300 million of 18-month floating rate Series D Senior Notes with a maturity date of September 20, 2013 and a coupon rate based on the three-month LIBOR rate plus a credit spread of 75 basis points, which resets every three months. As of December 31, 2012, the interest rate on these notes was 1.059 percent. The proceeds, net of issuance costs, were used to repay the NU parent $263 million Series A Senior Notes that matured on April 1, 2012, to repay short-term borrowings and for other general corporate purposes.

On March 22, 2012, the FERC approved CL&P's application requesting to increase its total short-term borrowing capacity from a maximum of $450 million to a maximum of $600 million through December 31, 2013.

On March 26, 2012, CL&P entered into a five-year $300 million unsecured revolving credit facility. The credit facility is intended to finance short-term borrowings that CL&P incurred to fund costs of restoring power following Tropical Storm Irene and the October 2011 snowstorm. Under this new facility, CL&P can borrow either on a short-term or a long-term basis subject to any necessary regulatory approval, and may borrow at prime rates or LIBOR-based rates, plus an applicable margin based on the higher of S&P s or Moody s credit ratings. As of December 31, 2012, CL&P had $89 million in borrowings outstanding under this credit facility. The weighted-average interest rate on these borrowings as of December 31, 2012 was 3.325 percent.

On April 2, 2012, CL&P remarketed $62 million of tax-exempt PCRBs that were subject to mandatory tender on that date. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.55 percent during the current three-year fixed-rate period, and are subject to mandatory tender for purchase on April 1, 2015.

On May 16, 2012, the FERC granted authorization to allow NSTAR Electric to issue total short-term debt securities in an aggregate principal amount not to exceed $655 million outstanding at any one time, effective October 23, 2012 through October 23, 2014.

On July 25, 2012, NU, CL&P, NSTAR LLC, NSTAR Gas, PSNH, WMECO, and Yankee Gas jointly entered into a five-year $1.15 billion revolving credit facility. The new facility replaced (1) the NSTAR LLC revolving credit facility of $175 million that served to backstop a commercial paper program utilized by NSTAR LLC and was scheduled to expire on December 31, 2012, (2) the NSTAR Gas revolving credit facility of $75 million that expired on June 8, 2012, and (3) the CL&P, PSNH, WMECO, and Yankee Gas joint $400 million and NU parent $500 million unsecured revolving credit facilities that were scheduled to expire on September 24, 2013. The new facility expires on July 25, 2017. We expect the new facility to be used primarily to backstop the $1.15 billion commercial paper program at NU, which commenced July 25, 2012. As of December 31, 2012, NU had $1.15 billion in borrowings outstanding under this commercial paper program. The weighted-average interest rate on these borrowings as of December 31, 2012 was 0.46 percent, which is generally based on money market rates. As of December 31, 2012, there were inter-company loans of $987.5 million from NU to its subsidiaries ($405.1 million for CL&P, $63.3 million for PSNH, and $31.9 million for WMECO).

On July 25, 2012, NSTAR Electric entered into a five-year $450 million revolving credit facility. This new facility serves to backstop NSTAR Electric s existing $450 million commercial paper program. The new facility expires on July 25, 2017. This new facility replaced a prior $450 million NSTAR Electric revolving credit facility that was scheduled to expire on December 31, 2012. As of December 31, 2012, NSTAR Electric had $276 million in short-term borrowings outstanding under its commercial paper program, leaving $174 million of available borrowing capacity. The weighted-average interest rate on these borrowings as of December 31, 2012 was 0.31 percent, which is generally based on money market rates.

On July 31, 2012, the DPU approved NSTAR Electric's application for a new two-year financing plan that provides for the issuance of long-term debt securities in an aggregate amount not to exceed $600 million prior to December 31, 2013.

On October 1, 2012, CL&P redeemed at par four different series of tax-exempt PCRBs totaling $116.4 million. The PCRBs carried coupons that ranged from 5.85 percent to 5.95 percent and maturity dates that ranged from 2016 through 2028. On October 1, 2012, WMECO redeemed at par $53.8 million of tax-exempt PCRBs. The PCRBs had a maturity date of 2028 and a coupon of 5.85 percent.

On October 4, 2012, WMECO issued at a premium $150 million of senior unsecured notes at a yield of 2.673 percent that will mature on September 15, 2021. The senior unsecured notes are part of the same series of WMECO s existing 3.5 percent coupon Series F Notes that were initially issued in September 2011. As a result, the aggregate principal amount of WMECO s outstanding Series F Notes now totals $250 million.

On October 15, 2012, NSTAR Electric issued at a discount $400 million of 2.375 percent Debentures at a yield of 2.406 percent that will mature on October 15, 2022. The proceeds, net of issuance costs, were used to pay $400 million of 4.875 percent Debentures that matured on October 15, 2012.

On January 15, 2013, CL&P issued $400 million of 2.5 percent first mortgage bonds that will mature on January 15, 2023. The proceeds, net of issuance costs, were used to repay CL&P s revolving credit facility borrowings of $89 million and $305.8 million of its commercial paper program borrowings.

NU, CL&P, NSTAR Electric, PSNH and WMECO use their available capital resources to fund their respective construction expenditures, meet debt requirements, pay costs, including storm-related costs, pay dividends and fund other corporate obligations, such as pension contributions. The current growth in NU s transmission construction expenditures utilizes a significant amount of cash for projects that have a long-term return on investment and recovery period. In addition, NU s Regulated companies operate in an environment where recovery of its electric and natural gas distribution construction expenditures takes place over an extended period of time. This impacts the timing of the revenue stream designed to fully recover the total investment plus a return on the equity portion of the cost and related financing costs. These factors have resulted in NU s current liabilities exceeding current assets by approximately $1.4 billion, $268 million, $198 million and $60 million at NU, CL&P, NSTAR Electric and WMECO, respectively, as of December 31, 2012.

As of December 31, 2012, approximately $730 million of NU's current liabilities relates to long-term debt that will be paid in the next 12 months, consisting of $550 million for NU parent, $55 million for WMECO, and $125 million for CL&P. NU, with its strong credit ratings, has several options available in the financial markets to repay or refinance these maturities with the issuance of new long-term debt. NU, CL&P, NSTAR Electric, and WMECO will reduce their short-term borrowings with cash received from operating cash flows or with the issuance of new long-term debt, as deemed appropriate given our capital requirements and maintenance of our credit rating and profile. Management expects the future operating cash flows of NU and its subsidiaries, along with the access to financial markets, will be sufficient to meet any future operating requirements and capital investment forecasted opportunities.

Cash flows provided by operating activities in 2012 totaled $1.05 billion, compared with operating cash flows of $901.1 million in 2011 and $832.6 million in 2010 (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 addition of NSTAR, which contributed $450.8 million of operating cash flows (net of RRB payments) to NU since the date of the merger, April 10, 2012. Offsetting the favorable NSTAR cash flow impact was an increase of $100.6 million in cash disbursements made in 2012, compared to 2011, associated with CL&P, PSNH and WMECO storm restoration costs related to Tropical Storm Irene, the October 2011 snowstorm, and Hurricane Sandy, NUSCO Pension Plan cash contributions of $197.4 million in 2012, compared to $143.6 million in 2011, a total of $28 million of bill credits in 2012 to customers of CL&P and WMECO related to the merger, and $27 million in bill credits provided to CL&P residential customers in 2012 related to the October 2011 snowstorm. In addition, there were approximately $42 million of NU parent transaction cost payments related to the merger. The improved cash flows from 2010 to 2011 were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010, 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 $143.6 million of Pension Plan cash contributions 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.

A summary of the current credit ratings and outlooks by Moody's, S&P and Fitch for senior unsecured debt of NU parent, NSTAR Electric, and WMECO and senior secured debt of CL&P and PSNH is as follows:

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

On February 14, 2013, S&P revised its criteria for rating utility first mortgage bonds, resulting in one-level upgrades of CL&P and PSNH first mortgage bonds by S&P.

We paid common dividends of $375 million in 2012, compared with $194.6 million in 2011. This reflects an increase of approximately 17 percent in our common dividend beginning in the second quarter of 2012 following an increase of approximately 7 percent in the first quarter of 2012. On February 5, 2013, our Board of Trustees approved a common dividend payment of $0.3675 per share, payable March 28, 2013 to shareholders of record as of March 1, 2013. The dividend represented an increase of 7.1 percent over the $0.343 per share quarterly dividend paid in December 2012.

In 2012, CL&P, NSTAR LLC, PSNH, and WMECO paid $100.5 million, $141 million, $90.7 million, and $9.4 million, respectively, in common dividends to NU parent. Since April 10, 2012, NSTAR Electric and NSTAR Gas have paid $159.9 million and $12 million, respectively, in common dividends to NSTAR LLC. NU parent made equity contributions to CL&P and WMECO of $25 million and $50 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, 2012, 2011 and 2010 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2012** [(1)]	**2011**	**2010**

CL&P	$ 449.1	$ 424.9	$ 380.3
NSTAR Electric	324.3	N/A	N/A
PSNH	203.9	241.8	296.3
WMECO	264.2	238.0	115.2
Natural Gas	148.7	98.2	82.5
NPT	33.5	24.9	7.5
Other	48.6	48.9	72.7
Total	$ 1,472.3	$ 1,076.7	$ 954.5

(1)

Cash capital expenditures include NSTAR from the date of merger, April 10, 2012, through December 31, 2012.

The increase in our cash capital expenditures was the result of the addition of NSTAR s capital expenditures, effective April 10, 2012, and higher transmission segment cash capital expenditures of $113.8 million, primarily at WMECO and CL&P.

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 $1.5 billion in 2012, $1.2 billion in 2011, and $1 billion in 2010. These amounts included $43.1 million in 2012, $51.9 million in 2011, and $68.7 million in 2010, related to our corporate service companies, NUSCO and RRR.

Transmission Business: Transmission business capital expenditures increased by $189.6 million in 2012, compared with 2011, due primarily to increases at CL&P and WMECO related to the construction of GSRP and the addition of NSTAR Electric's capital expenditures since April 10, 2012. A summary of transmission capital expenditures by company in 2012, 2011 and 2010 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars)	**2012** (1)		**2011**		**2010**	
CL&P	$	182.5	$	128.6	$	107.2
NSTAR Electric		160.7		N/A		N/A
PSNH		55.7		68.1		49.1
WMECO		214.7		236.8		95.2
NPT		35.4		25.9		9.4
Total Transmission Segment	$	649.0	$	459.4	$	260.9

(1)

Transmission capital expenditures include NSTAR Electric from the date of merger, April 10, 2012, through December 31, 2012.

NEEWS: GSRP, a project that involves the construction of 115 kV and 345 kV overhead lines by CL&P and WMECO from Ludlow, Massachusetts to Bloomfield, Connecticut, is the first, largest and most complicated project within the NEEWS family of projects. The $718 million project is expected to be fully placed in service in late 2013. As of December 31, 2012, the project was approximately 93 percent complete and we have placed $298 million in service.

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. All siting applications have been filed by CL&P and National Grid. On January 2, 2013, the Connecticut Siting Council issued a final decision and order approving the Connecticut portion of the project. Decisions in Rhode Island and Massachusetts are expected between the end of 2013 and early 2014. The $218 million project is expected to be placed in service in late 2015.

Included as part of NEEWS are associated reliability related projects, approximately $70 million of which have been placed in service and approximately $30 million of which are in various phases of construction and will continue to go into service through 2013.

Through December 31, 2012, CL&P and WMECO had capitalized $212 million and $518.1 million, respectively, in costs associated with NEEWS, of which $79.4 million and $183.4 million, respectively, were capitalized in 2012.

Greater Hartford Central Connecticut Project (GHCC): In August 2012, ISO-NE presented its preliminary needs analysis for the GHCC to the ISO-NE Planning Advisory Committee. The results showed severe thermal overloads and voltage violations in each of the four study areas now and in the near future. A combination of 345 kV and 115 kV transmission solutions are being considered to address these reliability concerns and a set of preferred solutions are expected to be identified by ISO-NE in 2013. Approximately $300 million has been included in our five-year capital program for future projects being identified to enhance these reliability concerns, which have recently been confirmed by ISO-NE.

Cape Cod Reliability Projects: Transmission projects serving Cape Cod in the Southeastern Massachusetts (SEMA) reliability region consist of an expansion and upgrade of NSTAR Electric's existing transmission infrastructure including construction of a new 345 kV transmission line that will cross the Cape Cod Canal (The Lower SEMA Transmission Project) as well as a new 115kV transmission line and other 115kV upgrades in the center of Cape Cod. All regulatory and licensing and permitting is complete for the Lower SEMA Transmission Project. Construction commenced in September 2012 and is expected to be completed by mid-2013. The total estimated construction cost for the Cape Cod projects is approximately $150 million.

Northern Pass: Northern Pass is NPT's 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. Effective April 10, 2012, as a result of the merger, NUTV owned 100 percent of NPT. NPT has identified a new route in the northern-most part of the project s route where PSNH did not own any rights of way. We expect to file the new route with the DOE in the first quarter of 2013, and we believe that NPT will be completed in early 2017.

We estimate the costs of the Northern Pass transmission project will be approximately $1.2 billion (including capitalized AFUDC).

Greater Boston Reliability and Boston Network Improvements: As a result of continued analysis of the transmission needs to enhance system reliability and improve capacity in eastern Massachusetts, NSTAR Electric expects to implement a series of new transmission initiatives over the next five years. We have included $479 million in our five-year capital program related to these initiatives.

Distribution Business: A summary of distribution capital expenditures by company for 2012, 2011 and 2010 is as follows:

	For the Year Ended December 31,		
(Millions of Dollars)	**2012** (1)	**2011**	**2010**
CL&P:			
Basic Business	$ 69.2	$ 166.6	$ 126.2
Aging Infrastructure	177.8	112.3	104.0
Load Growth	65.8	59.6	75.2
Total CL&P	312.8	338.5	305.4
NSTAR Electric:			
Basic Business	47.3	N/A	N/A
Aging Infrastructure	111.5	N/A	N/A
Load Growth	17.4	N/A	N/A
Total NSTAR Electric	176.2	N/A	N/A
PSNH:			
Basic Business	25.3	47.7	41.2
Aging Infrastructure	50.2	25.3	19.5
Load Growth	20.2	25.8	23.1
Total PSNH	95.7	98.8	83.8
WMECO:			
Basic Business	12.7	24.2	17.5
Aging Infrastructure	18.5	11.5	10.5
Load Growth	6.5	6.1	5.1
Total WMECO	37.7	41.8	33.1
Total - Electric Distribution (excluding Generation)	622.4	479.1	422.3
Total - Natural Gas	162.9	102.8	94.6
Other Distribution	0.1	1.0	2.0
Total Electric and Natural Gas	785.4	582.9	518.9
PSNH Generation:			
Clean Air Project	22.0	101.1	149.7
Other	7.9	23.7	27.4
Total PSNH Generation	29.9	124.8	177.1
WMECO Generation	0.7	11.7	10.1
Total Distribution Segment	$ 816.0	$ 719.4	$ 706.1

(1)

Distribution capital expenditures include NSTAR Electric and NSTAR Gas from the date of merger, April 10, 2012, through December 31, 2012.

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

Clean Air Project: In June 2012, PSNH placed into service the last major elements of the Clean Air Project at Merrimack Station, a $421 million project that is utilizing wet scrubber technology to significantly reduce mercury and sulfur emissions from the station s two coal units. The scrubber has been operating since the end of September 2011 and has reduced mercury and sulfur emissions by more than 95 percent.

CL&P System Resiliency Plan: On January 16, 2013, PURA approved the $300 million plan CL&P filed to improve the resiliency of its electric distribution system. Consistent with the terms of the Connecticut settlement agreement, the plan includes vegetation management (both enhanced tree trimming and trimming on a shorter cycle), structural hardening (strengthening field structures through upgrades to the current structure design and material standards as well as upgrades to the poles and conductors), and electrical hardening (upgrading electrical distribution conductors and protective devices on overhead circuits). CL&P expects to complete the plan in five years in two separate phases. Phase 1 of the plan, which will be primarily focused on vegetation management, is estimated to cost $32 million in 2013 and $53 million in 2014. Phase 2 of the plan is estimated to cost the remaining $215 million over the period from 2015 through 2017.

Projected Capital Expenditures: A summary of the projected capital expenditures for the Regulated companies' electric transmission business for 2013 through 2017 and for their distribution business for 2013 through 2015, including our corporate service companies' capital expenditures on behalf of the Regulated companies, is as follows:

	Year					
(Millions of Dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**2013-2017 Total**
CL&P Transmission	$ 193	$ 243	$ 157	$ 135	$ 89	$ 817
NSTAR Electric Transmission	211	198	278	222	248	1,157
PSNH Transmission	92	147	102	63	15	419
WMECO Transmission	95	102	77	11	2	287
NPT	45	84	235	394	447	1,205
Total Transmission	$ 636	$ 774	$ 849	$ 825	$ 801	$ 3,885
Electric Distribution	670	648	635			
Generation	30	30	34			
Natural Gas	170	160	161			
Total Distribution	$ 870	$ 838	$ 830			
Corporate Service Companies	$ 84	$ 62	$ 55			
Total	$ 1,590	$ 1,674	$ 1,734			

Actual capital expenditures could vary from the projected amounts for the companies and periods above.

FERC Regulatory Issues

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, NSTAR Electric, 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, which would be effective September 30, 2011 through December 31, 2012. In response, the New England transmission owners filed testimony and analysis based on standard FERC methodology and precedent, demonstrating that the base ROE of 11.14 percent remained just and reasonable.

On May 3, 2012, the FERC issued an order establishing hearing and settlement procedures for the complaint. The settlement proceedings were subsequently terminated, as the parties had reached an impasse in their efforts to reach a settlement. In August 2012, the FERC trial judge assigned to the complaint established a schedule for the trial phase of the proceedings. Complainant testimony supporting a base ROE of 9 percent was filed on October 1, 2012. Additional testimony was filed on October 1, 2012 by a group of Massachusetts municipal electric companies, which recommended a base ROE of 8.2 percent. The New England transmission owners filed testimony and analysis on November 20, 2012, demonstrating they believe that the current base ROE continues to be just and reasonable. On January 18, 2013, the FERC trial staff filed testimony and analysis recommending a base ROE of 9.66 percent based on the midpoint of their analysis with a range of reasonableness of 6.82 percent to 12.51 percent. Hearings on this complaint are scheduled for May 2013 and a trial judge s recommended decision is due in September 2013. A decision from FERC commissioners is expected in 2014. Refunds to customers, if any, as a result of a reduction in the NU transmission companies base ROE would be retroactive to October 1, 2011.

On December 27, 2012, several additional parties filed a separate complaint concerning the New England transmission owners' base ROE with the FERC. This new complaint seeks to reduce the New England transmission owner s base transmission ROE effective January 1, 2013, and to consolidate this new complaint with the joint complaint filed on September 30, 2011. The New England transmission owners have asked the FERC to reject this new complaint. The FERC has not yet acted on this request.

As of December 31, 2012, CL&P, NSTAR Electric, PSNH, and WMECO had approximately $2.1 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 $2.1 million. We cannot at this time predict the ultimate outcome of this proceeding or the estimated impact on CL&P s, NSTAR Electric s, PSNH s, or WMECO s respective financial position, results of operations or cash flows.

FERC Order No. 1000: On October 25, 2012, ISO-NE and a majority of the New England transmission owners, including CL&P, NSTAR Electric, PSNH and WMECO, made a comprehensive compliance filing as required by FERC Order No. 1000 and Order No. 1000-A, issued on July 21, 2011 and May 17, 2012, respectively. The compliance filing first seeks to preserve the existing reliability planning process in New England, based on FERC s previous approval of transmission owners rights under the Transmission Operating Agreement with ISO-NE, and the superiority of the current planning process, which has resulted in major transmission construction, large reliability benefits and reduction of market costs. The filing also contains a new process for public policy transmission planning that incorporates opportunities for competing, non-incumbent projects and cost allocation among the supporting states. In mid-January 2013, ISO-NE and the majority of New England transmission owners filed answers to various stakeholders that submitted protests to the compliance filing. We cannot predict the final outcome or impact on us; however implementation of FERC s goals in New England, including within our service territories, may expose us to competition for construction of transmission projects, additional regulatory considerations, and potential delay with respect to future transmission projects.

Regulatory Developments and Rate Matters

Federal:

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. PSNH and other electric utility groups filed thousands of pages of comments contesting EPA s draft permit requirements. PSNH stated that the data and studies supplied to the EPA demonstrate the fact that a closed-cycle cooling system is not warranted. The EPA does not have a set deadline to consider comments and to issue a final permit. 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 face similar permitting determinations.

Major Storms:

2013, 2012 and 2011 Major Storms: On August 28, 2011, Tropical Storm Irene caused extensive damage to our distribution system. Approximately 800,000 CL&P, PSNH and WMECO customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut. Approximately 500,000 customer outages occurred on the NSTAR Electric distribution system in its aftermath.

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 CL&P, PSNH and WMECO s 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 western 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; and the most severe in WMECO's history. The storm also caused approximately 200,000 customer outages on the NSTAR Electric distribution system.

On October 29, 2012, Hurricane Sandy caused extensive damage to our electric distribution system across all three states. Approximately 1.5 million of our 3.1 million electric distribution customers were without power during or following the storm, with approximately 850,000 of those customers in Connecticut, approximately 472,000 in Massachusetts, and approximately 137,000 in New Hampshire.

As of December 31, 2012, deferred storm restoration costs related to these major storms that are deferred for future recovery at CL&P, NSTAR Electric, PSNH, and WMECO were as follows:

(Millions of Dollars)	**Tropical Storm Irene**	**October Snowstorm**	**Hurricane Sandy**	**Total**
CL&P	$ 108.6	$ 173.0	$ 159.9	$ 441.5
NSTAR Electric	21.9	13.9	27.8	63.6
PSNH	6.8	15.5	12.1	34.4
WMECO	3.2	23.3	4.2	30.7
Total	$ 140.5	$ 225.7	$ 204.0	$ 570.2

On February 8, 2013, a blizzard caused damage to the electric delivery systems of CL&P and NSTAR Electric. We have estimated that approximately 71,000 and 350,000 of CL&P and NSTAR Electric's distribution customers, respectively, were without power during or following the storm. We believe that this storm will cost between $100 million to $120 million, with approximately 90 percent of those costs relating to NSTAR Electric. Management expects the costs to meet the criteria for specific cost recovery in Connecticut and Massachusetts and, as a result, does not expect the storm to have a material impact on the results of operations of CL&P or NSTAR Electric. Each operating company will seek recovery of these anticipated deferred storm costs through its applicable regulatory recovery process.

The magnitude of these storms   restoration costs and damages met the criteria for cost deferral in Connecticut, New Hampshire, and Massachusetts and as a result, the storms had no material impact on the results of operations of CL&P, NSTAR Electric, PSNH and WMECO. As covered by the Connecticut settlement agreement, CL&P agreed to forego recovery of $40 million (pre-tax) of the deferred storm restoration costs associated with Tropical Storm Irene and the October 2011 snowstorm. We believe our response to all storms was prudent and therefore we believe it is probable that CL&P, NSTAR Electric, PSNH and WMECO will be allowed to recover the deferred storm restoration costs. Each operating company will seek recovery of its estimated deferred storm restoration costs through its applicable regulatory recovery process.

Connecticut:

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. Effective January 1, 2013, the PURA approved a decrease to CL&P s total average SS rate of approximately 4.5 percent and an increase to CL&P s total average LRS rate of approximately 15.3 percent. The energy supply portion of the total average SS rate decreased from 8.443 cents per kWh to 7.68 cents per kWh while the energy supply portion of the total average LRS rate increased from 6.06 cents per kWh to 7.679 cents per kWh. These changes were due primarily to the market conditions for the procurement of energy. CL&P is fully recovering from customers the costs of its SS and LRS services.

CTA and SBC Reconciliation: On December 12, 2012, PURA approved CL&P s 2011 CTA and SBC reconciliation as filed on March 30, 2012, which compared CTA and SBC revenues to revenue requirements. Prospectively, PURA has required CL&P to include only the billed revenues when filing its future CTA and SBC reconciliations. This adjustment to the filing will have no impact to CL&P s financial position, results of operations or cash flows. CL&P will file its 2012 CTA and SBC reconciliation in March 2013.

FMCC Filing: Semi-annually, CL&P files with PURA its FMCC filing, which reconciles actual FMCC revenues and charges and GSC revenues and expenses, for the six-month period under consideration. The filing identifies a total net over or under recovery, which includes the remaining uncollected or non-refunded portions from previous filings. On February 22, 2013, CL&P filed with PURA its semi-annual FMCC filing for the period July 1, 2012 through December 31, 2012. This filing also reflects the January 1, 2012 through June 30, 2012 amounts as approved by PURA in the previous semi-annual filing. The filing identified a total net over recovery of $7.9 million for the period. PURA has not established a schedule for review of this filing, however, 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.

Conservation Adjustment Mechanism: On November 7, 2012, CL&P filed an application with PURA for the establishment of a CAM. The CAM would collect the costs associated with expanded energy efficiency programs beyond that already collected through the statutory charge and the revenues lost because of the expanded energy efficiency programs.

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. At the time, CL&P had 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. In lieu of a decision from the Connecticut Supreme Court, the parties involved, including CL&P, agreed to resolve all issues associated with the 2004, 2005 and 2006 procurement fee and settle the matter. On October 2, 2012, the PURA issued a decision approving the parties joint settlement agreement. As a result of the joint settlement agreement, CL&P is allowed to retain $11.5 million of procurement incentives for the years 2004, 2005 and 2006.

PURA Storm Review: On August 1, 2012, PURA issued a final decision in the investigation of CL&P s performance related to both Tropical Storm Irene and the October 2011 snowstorm. The decision concluded that CL&P was deficient and inadequate in its preparation, response, and communication in both storms, and identified certain penalties that could be imposed on CL&P during its next rate case, including a reduction in allowed regulatory ROE and the disallowance of certain deferred storm restoration costs. However, PURA will consider and weigh the extent to which CL&P has taken steps in its restructuring of storm management and the establishment of new practices for execution in future storm response in determining any potential penalties. We believe such steps to improve current storm preparation and response practices have been successfully executed in recent storms. At this time, we cannot estimate the impact on CL&P s financial position, results of operations or cash flows. We continue to believe that CL&P's response to these 2011 storms was prudent and consistent with industry standards, and that it is probable that it will be able to recover its deferred costs.

System Resiliency Plan: On January 16, 2013, PURA approved the $300 million plan CL&P filed on July 9, 2012 to improve the resiliency of the CL&P electric distribution system. For further information, see "Business Development and Capital Expenditures Distribution Business" in this *Management's Discussion and Analysis.*

PURA Establishment of Performance Standards for Electric and Gas Companies Docket: On November 1, 2012, PURA issued its report to the Connecticut legislature concerning specific standards for acceptable performance for electric and gas companies under emergency situations. Emergency situations were defined as more than 10 percent of electric customers and 1 percent of gas customers being without service for more than 48 consecutive hours. The performance standards the electric and gas companies, including CL&P and Yankee Gas, were directed to incorporate into their emergency response plans (ERP), and implement into their operations, include (1) the National Incident Management System and utilization of the Incident Command System, (2) scalable action and trigger points for various levels of outages, (3) a damage assessment model and mode of delivery, (4) guidelines for setting

restoration priorities, (5) a description of how the utility will insure safety for the public and utility s employees, (6) a storm matrix for various storm levels that identify the mutual aid and/or contractor resources necessary to restore customers within a prescribed period of time, (7) written communication protocols for timely and accurate information exchange between the EDC and a pre-determined list of state and local agencies and other utilities during emergency events, (8) training and drills/exercises to be conducted annually on a local level and every 3 years on a state-wide level, and (9) a written report to be filed with PURA within 60 days after the end of an event in order to assist in lessons learned and continual improvement. Electric and gas companies, including CL&P and Yankee Gas, will be subject to penalties levied by PURA for failure to meet these performance standards.

Massachusetts:

Basic Service Rates: Electric distribution companies in Massachusetts are required to obtain and resell power to retail customers through Basic Service for those customers who choose not to buy energy from a competitive energy supplier. Basic Service rates are reset every six months (every three months for large commercial and industrial customers). The price of Basic Service is intended to reflect the average competitive market price for electric power. NSTAR Electric and WMECO fully recover their energy costs through DPU-approved regulatory rate mechanisms.

DPU Storm Penalties: On December 11, 2012, in separate orders issued by the DPU, NSTAR Electric and WMECO received penalties related to the investigation into the electric utilities responses to Tropical Storm Irene and the October 2011 snowstorm. The DPU ordered penalties of $4.1 million and $2 million for NSTAR Electric and WMECO, respectively, stating that NSTAR Electric failed to communicate and prioritize restoration efforts in both storms and WMECO failed to prioritize restoration efforts in the October snowstorm. These penalties were ordered to be assessed in the form of customer credits in 2013. On December 28, 2012, NSTAR Electric and WMECO each filed appeals with the SJC arguing the DPU penalties should be vacated. In their filings, NSTAR Electric and WMECO stated that the DPU s decision to assess the penalties was in error as the assessments were arbitrary and not supported by substantial evidence. While we believe that NSTAR Electric and WMECO should ultimately prevail upon appeal, we are unable to conclusively state that a favorable outcome is probable. Therefore, NSTAR Electric and WMECO recorded $4.1 million and $2 million, respectively, in pre-tax penalty charges as of December 31, 2012.

DPU Safety and Reliability Programs (CPSL): Since 2006, NSTAR Electric has been recovering incremental costs related to the Double Pole Inspection, Replacement/Restoration and Transfer Program and the Underground Electric Safety Program, which included stray-voltage remediation, manhole inspections, repairs, and upgrades, in accordance with this DPU approved program. Recovery of these CPSL costs is subject to review and approval by the DPU through a rate-reconciling mechanism. From 2006 through December 31, 2011, cumulative costs associated with the CPSL program resulted in an incremental revenue requirement to customers of approximately $83 million. These amounts included incremental operations and maintenance costs and the related revenue requirement for specific capital investments relative to the CPSL programs.

On May 28, 2010, the DPU issued an order on NSTAR Electric s 2006 CPSL cost recovery filing (the May 2010 Order). The May 2010 Order was the basis NSTAR Electric used for recognizing revenue for the CPSL programs. On October 8, 2010, NSTAR Electric submitted a Compliance Filing with the DPU reconciling the cumulative CPSL program activity for the periods 2006 through 2009 in order to determine a proposed rate adjustment effective on January 1, 2011. The DPU allowed the proposed rates for the CPSL programs to go into effect on that date, subject to final reconciliation of CPSL program costs through a future DPU proceeding. NSTAR Electric updated the October 2010 filing with final activity through 2011 in February 2013.

NSTAR Electric cannot predict the timing of any subsequent DPU order related to its CPSL filings for the period 2006 through 2011. Therefore, NSTAR Electric continued to record its 2006 through 2011 revenues under the CPSL programs based on the May 2010 Order. While we do not believe that any subsequent DPU order would result in revenue recognition that is materially different than the amounts already recognized, it is reasonably possible that an order could have a material impact on NSTAR Electric s results of operations, financial position and cash flows.

The April 4, 2012 DPU-approved comprehensive merger settlement agreement with the Massachusetts Attorney General concerning the Merger stipulates that NSTAR Electric must incur a revenue requirement of at least $15 million per year for 2012 through 2015 in order to continue these programs. CPSL revenues will end once NSTAR Electric has recovered its 2015-related CPSL costs. Realization of these revenues is subject to maintaining certain performance metrics over the four-year period and DPU approval. As of December 31, 2012, NSTAR Electric was in compliance with the performance metrics and has recognized the entire $15 million revenue requirement during 2012, which we believe is probable of approval from the DPU.

Basic Service Bad Debt Adder: In accordance with a generic DPU order, electric utilities in Massachusetts recover the energy-related portion of bad debt costs in their Basic Service rates. On February 7, 2007, NSTAR Electric filed its 2006 Basic Service reconciliation with the DPU proposing an adjustment related to the increase of its Basic Service bad debt charge-offs. On June 28, 2007, the DPU issued an order approving the implementation of a revised Basic Service rate. However, the DPU instructed NSTAR Electric to reduce distribution rates by an amount equal to the increase in its Basic Service bad debt charge-offs. This adjustment to NSTAR Electric s distribution rates would eliminate the fully reconciling nature of the Basic Service bad debt adder.

NSTAR Electric deferred the unrecovered costs associated with energy-related bad debt as a regulatory asset, which totaled approximately $34 million as of December 31, 2011, as NSTAR Electric had concluded that these costs were probable of recovery in future rates. On June 18, 2010, NSTAR Electric filed an appeal of the DPU s order with the SJC, which was heard by the SJC in

December 2011. On April 11, 2012, the SJC issued a procedural order waiving its standing 130-day rule for issuance of an order on the matter. Due to the delay, NSTAR Electric concluded that while an ultimate outcome on the matter in its favor remained more likely than not, it could no longer be deemed probable. As a result, NSTAR Electric recognized a reserve of $28 million ($17 million after-tax) as a charge to Operations and Maintenance in the first quarter of 2012 to reserve the related regulatory asset on its balance sheet.

On June 4, 2012, the SJC vacated the DPU's June 28, 2007 order and remanded the matter to the DPU for a "statement of reasons, including subsidiary findings, of its conclusion of law and relevant facts." The continued uncertainty of the outcome of the DPU s proceeding leaves NU and NSTAR Electric unable to conclude that it is probable that the previously reserved amount will ultimately be recovered and therefore NSTAR Electric will continue to maintain a reserve on this amount until the ultimate outcome is determined by the DPU.

Renewable Energy Contract: On November 26, 2012, the DPU approved NSTAR Electric s renewable energy contract with Cape Wind Associates, LLC, which has a term of 15 years, to purchase 129 MW of renewable energy from an offshore wind energy facility once it is constructed and placed in service.

New Hampshire:

Distribution Rates: In 2012, PSNH filed for a step increase and a change in its accrual to its major storm reserve fund. On June 27, 2012, the NHPUC approved an annualized distribution rate increase of $7.1 million, effective July 1, 2012, for the step increase. Additionally, PSNH was allowed a $3.5 million increase in the annual accrual to its major storm reserve fund effective July 1, 2012.

ES and SCRC Rates: On December 12, 2012, PSNH filed an updated request to its September 28, 2012 preliminary request with the NHPUC to adjust its ES and SCRC rates effective with services rendered on and after January 1, 2013. PSNH s updated request proposed to increase the current ES billing rate to reflect projected costs for 2013 and to decrease the current SCRC billing rate to reflect the full amortization of RRBs at the end of April 2013. The net impact to customers that purchase energy from PSNH is a net increase of 1.287 cents per kWh in total rates. On December 28, 2012, the NHPUC approved the request.

ES Temporary Rates: On November 22, 2011, the NHPUC opened a docket to review the Clean Air Project including the establishment of temporary rates for near-term recovery of Clean Air Project costs, a prudence review of PSNH's overall construction program, and establishment of permanent rates for recovery of prudently incurred Clean Air

Project costs. On April 10, 2012, the NHPUC issued an order authorizing temporary rates, effective April 16, 2012, which recover a significant portion of the Clean Air Project costs, including a return on equity. The docket will continue for a comprehensive prudence review of the Clean Air Project and the establishment of a permanent rate. The temporary rates will remain in effect until a permanent rate allowing full recovery of all prudently incurred costs is approved. At that time, the NHPUC will reconcile recoveries collected under the temporary rates with final approved rates.

The NHPUC had suspended the procedural schedule for the prudence review pending issuance of an order on preliminary substantive and procedural matters. On December 24, 2012, the NHPUC issued an Order ruling on the requirement of PSNH to respond to a number of discovery requests that PSNH had objected to, and deciding that PSNH had legal authority to seek a variance from the Clean Air Project Mandate in the event of "economic infeasibility." PSNH has sought rehearing of that December 24th Order. The NHPUC is considering PSNH s rehearing request, and has again suspended the procedural schedule. PSNH expects hearings to commence in this proceeding on or about the third quarter of 2013. We cannot predict the outcome of the Clean Air Project prudence review, but believe all costs were incurred appropriately and are probable of recovery.

ES Filing: 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 April 27, 2012, PSNH filed its proposed Alternative Default Energy Rate that addresses customer migration, with an effective date of July 1, 2012. The proposal, if implemented, would result in no impact to earnings and would allow for an increased contribution to fixed costs for all ES customers. On May 24, 2012, the NHPUC suspended the effectiveness of the proposed rates pending hearings. Hearings were held on October and November 2012 and a final decision is expected in the first quarter of 2013.

Default ES Rate: On January 18, 2013, the NHPUC opened a docket to investigate market conditions affecting PSNH s energy service rate, how PSNH will maintain just and reasonable rates in light of those conditions, and any impact of PSNH s generation ownership on the New Hampshire competitive electric market. The NHPUC noted that this proceeding will not undertake to determine whether continued ownership and operation of generation is in PSNH s retail customers economic interest. No schedule or procedural process has been established for this proceeding.

Legislative and Policy Matters

Federal:

Moving Ahead for Progress in the 21st Century Act: On July 6, 2012, President Obama signed the "Moving Ahead for Progress in the 21st Century" Act, which included provisions that impact how minimum required contributions to qualified pension plans are calculated. The legislation allows NU to use a higher discount rate to calculate the plan's funded target liability, resulting in lower cash contribution

requirements. We have evaluated the impact of the legislation on future cash contributions to the NUSCO and NSTAR Pension Plans and will continue to follow our policy to fund these plans on an annual basis that is at least equal to the amounts that will satisfy the federal requirements, as amended by this legislation.

2013 Legislation: On January 2, 2013, President Obama signed into law the "American Taxpayer Relief Act of 2012," which extends certain tax rules allowing the accelerated deduction of depreciation from the "American Recovery and Reinvestment Act of 2009" to businesses through 2013. This extended stimulus is expected to provide us with cash flow benefits of between $200 million to $250 million in 2013 and 2014. We are still evaluating the other provisions of this legislation, which are not expected to have a significant impact on our financial position, results of operations or cash flows.

Connecticut:

Enhancing Emergency Preparedness and Response Act: On June 15, 2012, Connecticut enacted the "Enhancing Emergency Preparedness and Response Act," which is intended to enhance the state s emergency preparedness and response in the event of natural disasters. Among numerous provisions, the bill requires the PURA to establish emergency performance standards for utilities and allows the PURA to levy penalties of up to 2.5 percent of annual distribution revenues for failure to meet performance standards. For further information, see "Regulatory Developments and Rate Matters Connecticut" in this *Management's Discussion and Analysis.*

Comprehensive Energy Strategy: On February 19, 2013, Connecticut issued a final comprehensive energy strategy (strategy). The strategy includes a series of policy proposals that aim to expand energy choices, improve environmental conditions, create clean energy jobs, and enhance the quality of life for customers in the state. It also includes a seven-year initiative for expanding natural gas use with a goal of providing nearly 300,000 utility customers with access to natural gas, building an estimated 900 miles of new natural gas mains, and estimates of capital costs to be incurred by natural gas utility companies to connect customers on or near natural gas mains. In addition to natural gas expansion, the strategy also calls for a significant expansion of energy efficiency investment in Connecticut, a review of Connecticut s Renewable Energy Portfolio Standards (possibly including Canadian hydroelectric generation as a qualifying resource), and investment in alternative fuel transportation. Many of the recommendations in the strategy will require actions by the PURA and potentially the legislature. As such, the full impact of the strategy is not reflected in our electric distribution, transmission or natural gas business segments five-year capital program.

Massachusetts:

Energy Act: On August 3, 2012, Massachusetts Governor Patrick signed into law "An Act Relative to Competitively Priced Electricity in the Commonwealth" (Energy Act). The more significant provisions of the Energy Act impacting our Massachusetts operating companies and customers are as follows:

.

Requires electric utility companies to file a distribution rate case every five years and natural gas companies every 10 years, limiting those companies to one settlement agreement in a 10-year period;

.

Extends the distribution rate case review period to 10 months;

.

Requires all distribution companies, through a competitive bidding process and subject to DPU approval, to enter into additional cost-effective long-term renewable energy contracts with terms of 10 to 20 years. Electric utility companies will be allowed a remuneration of 2.75 percent of the annual payments under the contracts to compensate them for accepting the financial obligation of the contracts;

.

Orders the DPU to open a proceeding for each electric and natural gas utility company to identify reconciliation factors and establish cost recovery from each customer class under cost-based criteria; and

.

Allows electric utility or distribution companies to construct, own and operate no more than 25 MW of solar generation facilities, a decrease from the initial allowance of up to 50 MW of solar generation facilities, subject to DPU approval, and requires that construction be completed prior to June 30, 2015.

Storm Response Act: On August 6, 2012, Massachusetts Governor Patrick signed into law "an act relative to emergency service response of public utility companies" (Storm Response Act), to help improve utility companies emergency response and communication. The Storm Response Act codified certain emergency response plan (ERP) provisions, which require utility companies to submit an annual ERP for DPU review and approval. The ERP will describe storm or emergency responsibilities of utility company employees, customer communication processes and systems, and deployment of resources. The Storm Response Act also requires that all future financial penalties levied on utility companies by the DPU for violation of DPU storm and emergency service performance standards will be provided to customers, and that transmission companies performing vegetation management activities within a right-of-way comply with certain notification provisions. We are currently evaluating this act and its potential impacts on NSTAR Electric s, NSTAR Gas and WMECO s financial positions, results of operations and cash flows; however, we do not expect the impacts to be material.

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 the Audit Committee of our 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 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 3, "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. Because customers are billed throughout the month based on pre-determined cycles rather than on a calendar month basis, an estimate of electricity or natural gas delivered to customers for which the customers have not yet been billed is calculated as of the balance sheet date.

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 sales 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 unbilled sales to the respective customer classes, then applying an estimated rate by customer class to those 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 1K, "Summary of Significant Accounting Policies - Revenues," to the consolidated financial statements.

Pension and PBOP: NUSCO and NSTAR Electric sponsor pension plans covering certain of our employees. In addition, NUSCO and NSTAR Electric & Gas sponsor PBOP plans 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, 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 benefit expense (excluding SERP) for the Pension Plans was $234.9 million, $127.7 million and $80.4 million for the years ended December 31, 2012, 2011 and 2010, respectively. The pre-tax net periodic benefit expense for the PBOP Plans was $72.3 million, $43.6 million and $41.6 million for the years ended December 31, 2012, 2011 and 2010, respectively. NSTAR pension and PBOP expense is included in NU consolidated amounts from the date of the merger, April 10, 2012, through December 31, 2012.

We develop key assumptions for purposes of measuring liabilities as of December 31st 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.

<u>Long-Term Rate of Return on Plan Assets</u>: 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. For the year ended December 31, 2012, our aggregate expected long-term rate of return assumptions of 8.25 percent on the NUSCO Pension and PBOP Plans and 7.30 percent for the NSTAR Pension and PBOP Plans were used to determine our Pension and PBOP expense. For the forecasted 2013 pension

and PBOP expense, our expected long-term rate of return of 8.25 percent for all plans was used, which reflects a change in target asset allocations within both the NUSCO and NSTAR Pension and PBOP Plans.

Discount Rate: Payment obligations related to the Pension Plans and PBOP Plans are discounted at interest rates applicable to the expected timing of each plan s 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 4.24 percent for the NUSCO Pension Plan, 4.13 percent for the NSTAR Pension Plan, 4.04 percent for the NUSCO PBOP Plans and 4.35 percent for the NSTAR PBOP Plan as of December 31, 2012.

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, 2012 and 2011 for the NUSCO Pension Plan and 4 percent for the NSTAR Pension Plan as of December 31, 2012, which reflects our current expectation of future salary increases, including consideration of the levels of increases built into collective bargaining agreements.

Actuarial Determination of Expense: Pension and PBOP expense is determined by our actuaries and consists 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 for the NUSCO Pension and PBOP Plans by applying our assumed rate of return to a four-year rolling average of plan asset fair values, which reduces year-to-year volatility. This calculation recognizes investment gains or losses over a four-year period from the 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, 2012, investment gains and losses that remain to be reflected in the calculation of plan assets over the next four years were losses of $224.4 million and gains of $0.7 million for the NUSCO Pension Plan and PBOP Plans, 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. As of December 31, 2012, the net unrecognized actuarial losses on the NUSCO Pension and PBOP Plan liabilities were $1.1 billion and $176.5 million, respectively. For the NSTAR Pension and PBOP Plans, the entire difference between the actual and expected return on plan assets as of December 31, 2012 is immediately reflected as a component of unrecognized actuarial gains or losses to be amortized over the estimated average future service period of the employees. As of December 31, 2012, the net unrecognized actuarial losses on the NSTAR Pension and PBOP Plan liabilities were approximately $724 million and $176 million, respectively.

Forecasted Expenses and Expected Contributions: Based upon the assumptions and methodologies discussed above, we estimate that the combined expense for the Pension and PBOP Plans will be $241 million and $46 million, respectively, in 2013. 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 NUSCO PBOP Plans at the amount of PBOP expense excluding any curtailments and the NSTAR PBOP Plan at an amount that approximates benefit payments. NU's policy is to fund the Pension Plans annually in an amount at least equal to an amount that will satisfy the federal requirements. NU made contributions to the NUSCO Pension Plan totaling $197.4 million in 2012, of which $87.7 million was contributed by PSNH. NSTAR Electric contributed $25 million to the NSTAR Pension Plan in 2012. 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 94.8 percent and 100.2 percent as of January 1, 2012 for the NUSCO Pension Plan and NSTAR Pension Plan, respectively. We currently estimate that aggregate contributions of $285 million to the Pension Plans will be made in 2013. Fluctuations in the average discount rate used to calculate expected contributions to the Pension Plans can have a significant impact on the amounts.

Sensitivity Analysis: The following represents the hypothetical increase to the Pension Plans (excluding SERP) and PBOP Plans reported annual cost as a result of a change in the following assumptions by 50 basis points:

	Pension Plan Cost		PBOP Plan Cost	
(Millions of Dollars)	As of December 31,			
Assumption Change	**2012**	**2011**	**2012**	**2011**
NU Consolidated				
Lower long-term rate of return	$ 15.0	$ 10.3	$ 3.1	$ 1.3
Lower discount rate	$ 22.0	$ 14.2	$ 6.7	$ 2.3
Higher compensation increase	$ 10.4	$ 6.5	N/A	N/A
NSTAR Plans				
Lower long-term rate of return	$ 4.8	N/A	$ 1.7	N/A
Lower discount rate	$ 6.8	N/A	$ 4.1	N/A
Higher compensation increase	$ 3.6	N/A	N/A	N/A

Changes in pension and PBOP costs would not impact net income for the NSTAR Plans as their expenses are fully recovered in rates, which reconcile each year relative to the change in costs.

Health Care Cost: For the NUSCO PBOP Plans, the health care cost trend rate assumption is 7 percent, subsequently decreasing by 50 basis points per year to an ultimate rate of 5 percent in 2017. For the NSTAR PBOP Plan, the health care cost trend rate is 7.10 percent, subsequently decreasing to an ultimate rate of 4.50 percent in 2024. 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 $8.9 million in 2012, with a $126.5 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: We recorded approximately $3.2 billion of goodwill associated with the merger with NSTAR on April 10, 2012. NU had existing goodwill of $0.3 billion related to Yankee Gas. NU has identified its reporting units for purposes of allocating goodwill as Electric Distribution, Electric Transmission and Natural Gas Distribution. Our reporting units for purposes of allocating and testing goodwill are consistent with our operating segments underlying our reportable segments. Electric Distribution and Electric Transmission reporting units include values for the respective components of CL&P, NSTAR Electric, PSNH and WMECO. The Natural Gas reporting unit includes the carrying values of NSTAR Gas and Yankee Gas.

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 carrying 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 performed an impairment analysis as of October 1, 2012 for the Electric Distribution, Electric Transmission and Natural Gas Distribution reporting units. We determined that the fair value of the reporting units substantially exceeded the carrying values and no impairment exists. In performing the evaluation, we estimated the fair values of the reporting units and compared them to the carrying values of the reporting units, including goodwill. We estimated the fair values of the reporting units using a discounted cash flow approach and a market approach that analyzed company information and market transactions. This evaluation requires the input of several critical assumptions, including cash flow projections, operating cost escalation rates, rates of return, future growth rates, a risk-adjusted discount rate, long-term earnings and merger multiples of comparable companies.

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 the reporting unit s 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.

The 2012 goodwill impairment analysis resulted in a significant excess of fair value of our reporting units over the carrying value. The estimated fair value of our reporting units is sensitive to changes in assumptions, such as discount rates, peer company financial results, recent market transactions and forecasted cash flows.

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, non-tax deductible expenses, or 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 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 remediation options (ranging from no action required 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, the extent of our responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

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

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 our 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, the marketable securities held in CYAPC's and YAEC's nuclear decommissioning trusts, 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 on market risk, see Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," included in this Annual Report on Form 10-K.

For further information on derivative contracts and marketable securities, see Note 1I, "Summary of Significant Accounting Policies - Derivative Accounting," Note 5, "Derivative Instruments," and Note 6, "Marketable Securities," to the consolidated financial statements.

Other Matters

Accounting Standards Recently Adopted: For information regarding new accounting standards, see Note 1C, "Summary of Significant Accounting Policies   Recently Adopted Accounting Standards," to the consolidated financial statements.

Contractual Obligations and Commercial Commitments: Information regarding our contractual obligations and commercial commitments as of December 31, 2012 is summarized annually through 2017 and thereafter as follows:

NU

(Millions of Dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Long-term debt maturities (a)	$ 731.7	$ 576.6	$ 216.7	$ -	$ 745.0	$ 4,559.8	$ 6,829.8
Estimated interest payments on existing debt (b)	320.2	298.7	277.1	271.8	267.8	2,099.5	3,535.1
Capital leases (c)	2.8	2.2	2.2	2.0	2.0	7.5	18.7
Operating leases (d)	22.4	16.6	14.1	11.2	8.6	23.3	96.2
Funding of pension obligations (d) (h)	145.0	175.0	247.9	269.3	261.1	109.0	1,207.3
Funding of other postretirement benefit obligations (d)	55.7	52.0	49.5	46.1	43.8	11.7	258.8
Estimated future annual long-term contractual costs (e)	717.7	683.9	572.8	501.9	432.9	2,897.5	5,806.7
Other purchase commitments (d) (g)	1,876.8	-	-	-	-	-	1,876.8

Total [f] [i]	$ 3,872.3	$ 1,805.0	$ 1,380.3	$ 1,102.3	$ 1,761.2	$ 9,708.3	$ 19,629.4

52

CL&P

(Millions of Dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Long-term debt maturities [a]	$ 125.0	$ 150.0	$ 162.0	$ -	$ 250.0	$ 1,540.3	$ 2,227.3
Estimated interest payments on existing debt [b]	119.5	119.5	109.8	107.3	103.3	1,009.2	1,568.6
Capital leases [c]	2.2	2.0	2.0	1.9	2.0	7.3	17.4
Operating leases [d]	4.3	3.7	3.1	2.3	1.2	6.4	21.0
Funding of other postretirement benefit obligations [d]	8.1	7.0	6.2	5.0	4.3	3.6	34.2
Estimated future annual long-term contractual costs [e]	278.9	282.1	268.7	250.4	224.2	1,171.3	2,475.6
Other purchase commitments [d] [g]	751.4	-	-	-	-	-	751.4
Total [f] [i]	$ 1,289.4	$ 564.3	$ 551.8	$ 366.9	$ 585.0	$ 3,738.1	$ 7,095.5

(a)

Long-term debt maturities exclude fees and interest due for spent nuclear fuel disposal costs, net unamortized premiums and discounts, and other fair value adjustments.

(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 2012 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.

(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 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, 2012, 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 $40 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 2013.

(h)

These amounts represent NU's estimated minimum pension contributions to its qualified Pension Plan required under federal legislation. Contributions in 2014 through 2017 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)

Excludes other long-term liabilities, including the unrecognized tax benefits described above, deferred contractual obligations, environmental reserves, employee medical insurance reserves ($17.4 million at NU and $11.3 million at CL&P), workers compensation and long-term disability insurance reserves ($50 million at NU and $19.9 million at CL&P) and the ARO liability reserves as we cannot make reasonable estimates of the timing of payments.

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, 2012, 2011, and 2010. The year ended December 31, 2012 amounts include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012:

Comparison of 2012 to 2011:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2012 [a]**	**2011**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 6,273.8	$ 4,465.7	$ 1,808.1	40.5 %
Operating Expenses:				
Purchased Power, Fuel and Transmission	2,084.4	1,657.9	426.5	25.7
Operations and Maintenance	1,583.1	1,095.4	487.7	44.5
Depreciation	519.0	302.2	216.8	71.7
Amortization of Regulatory Assets, Net	79.8	91.1	(11.3)	(12.4)
Amortization of Rate Reduction Bonds	142.0	69.9	72.1	(b)
Energy Efficiency Programs	313.1	131.4	181.7	(b)
Taxes Other Than Income Taxes	434.2	323.6	110.6	34.2
Total Operating Expenses	5,155.6	3,671.5	1,484.1	40.4
Operating Income	$ 1,118.2	$ 794.2	$ 324.0	40.8 %

(a) The 2012 results include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012.
(b) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

	For the Years Ended December 31,			
(Millions of Dollars)	**2012 [a]**	**2011**	**Increase**	**Percent**
Electric Distribution	$ 4,716.5	$ 3,343.1	$ 1,373.4	41.1 %
Natural Gas Distribution	572.9	430.8	142.1	33.0

Total Distribution		5,289.4		3,773.9		1,515.5	40.2
Transmission		861.5		635.4		226.1	35.6
Total Regulated Companies		6,150.9		4,409.3		1,741.6	39.5
Other and Eliminations		122.9		56.4		66.5	(b)
Total Operating Revenues	$	6,273.8	$	4,465.7	$	1,808.1	40.5 %

(a) The 2012 results include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012.
(b) Percent greater than 100 percent not shown as it is not meaningful.

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

	For the Years Ended December 31,			
	2012 (a)	**2011**	**Increase**	**Percent**
Retail Electric Sales in GWh	49,718	33,812	15,906	47.0 %
Firm Natural Gas Sales in Million Cubic Feet	69,894	46,880	23,014	49.1 %

(a) Includes the retail electric and firm natural gas sales of NSTAR from the date of the merger, April 10, 2012, through
December 31, 2012.

Our Operating Revenues increased in 2012, as compared to 2011, due primarily to the addition of NSTAR, which included electric distribution revenues of approximately $1.7 billion, transmission revenues of approximately $50 million, natural gas revenues of approximately $200 million and other revenues of approximately $15 million, and the consolidation of CYAPC and YAEC revenues of approximately $40 million. Excluding the impact of NSTAR's operations and the consolidation of CYAPC and YAEC, our Operating Revenues decreased due to the following:

.

Lower electric distribution segment 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 tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. The tracked electric distribution revenues decreased due primarily to lower energy and supply-related costs ($241.8 million), lower CL&P CTA revenues ($46.3 million), lower wholesale revenues ($44.4 million), lower retail transmission revenues ($17.8 million), partially offset by higher CL&P FMCC delivery-related revenues ($82.4 million), higher SCRC revenues at PSNH ($34.2 million) and higher CL&P retail SBC revenues ($22.5 million).

.

A decrease in natural gas segment revenues due primarily to a 4.3 percent decrease in Yankee Gas' sales volume related to the warmer than normal weather in the heating season of 2012, as compared to the heating season of 2011. In addition, there was a decrease in the cost of natural gas, which is fully recovered in revenues from sales to our customers.

Partially offset by:

.

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, primarily at WMECO, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

.

An increase at PSNH related to the sale of oil to a third party ($20.8 million) in the second quarter of 2012, resulting in a benefit to customers through lower ES rates that does not impact earnings.

.

The portion of electric distribution segment revenues that impacts earnings increased $8.8 million due primarily to CL&P regulatory incentives of $11.5 million and C&LM incentives of $6.2 million at CL&P, partially offset by a decrease in retail electric sales related to the warmer than normal winter weather in 2012, as compared to the winter of 2011.

Purchased Power, Fuel and Transmission increased in 2012, as compared to 2011, due primarily to the following:

2012 Increase/(Decrease)

(Millions of Dollars)	**Compared to 2011**
The addition of NSTAR's operations	$ 640.0
Lower GSC supply costs, partially offset by higher CfD costs at CL&P	(124.3)
Lower natural gas costs and lower sales at Yankee Gas	(45.4)
Lower purchased transmission costs and lower Basic Service costs at WMECO	(25.4)
Lower purchased power costs, partially offset by higher transmission costs at PSNH	(8.6)
Other and eliminations	(9.8)
	$ 426.5

Operations and Maintenance increased in 2012, as compared to 2011, due primarily to the addition of NSTAR's operations, which included operating expenses of $320.8 million and maintenance expense of $50.4 million. Excluding the impact of NSTAR's operations, Operations and Maintenance increased due primarily to:

.

Higher NU parent and other companies' expenses ($70.1 million) that were due primarily to the increase in costs related to the completion of NU s merger with NSTAR ($55.9 million) and higher costs at NU s unregulated contracting business related to an increased level of work in 2012 ($16.3 million).

.

The establishment of a reserve related to major storm restoration costs ($40 million) at CL&P and bill credits to customers at CL&P and WMECO ($25 million and $3 million, respectively) as a result of the Connecticut and Massachusetts settlement agreements. In addition, there were higher electric distribution business expenses ($31.6 million) mainly as a result of general and administrative expenses primarily related to higher pension costs.

Partially offsetting these increases was the absence in 2012 of the storm fund reserve established in 2011 to provide bill credits to residential customers as a result of the October 2011 snowstorm and to provide contributions to certain Connecticut charitable organizations ($30 million) at CL&P, a decrease in the amortization of the regulatory deferral allowed in the 2010 rate case decision ($21.4 million) at CL&P and lower maintenance costs at PSNH s generation business due to less planned outage maintenance in 2012 ($17.8 million).

Depreciation increased in 2012, as compared to 2011, due primarily to the addition of NSTAR's utility plant balances ($148.4 million) and an increase as a result of the consolidation of CYAPC and YAEC ($40.3 million). Excluding the impact of NSTAR and the consolidation of CYAPC and YAEC, Depreciation increased due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net decreased in 2012, as compared to 2011, due primarily to a decrease in ES and TCAM amortization at PSNH ($46.9 million and $20.2 million, respectively), and higher CTA transition costs ($21.5 million) and lower CTA revenues ($46.3 million) at CL&P. Partially offsetting these decreases was an increase related to the addition of NSTAR's operations ($87.5 million), lower SBC costs ($7.6 million) and higher retail SBC revenues ($22.5 million) at CL&P, and an increase in SCRC amortization at PSNH ($13.5 million).

Amortization of RRBs increased in 2012, as compared to 2011, due primarily to the addition of NSTAR Electric s amortization ($67.7 million).

Energy Efficiency Programs increased in 2012, as compared to 2011, due primarily to the addition of NSTAR's operations ($169.4 million). In addition, there was an increase in expenses at WMECO attributable to an increase in spending in accordance with DPU approved energy efficiency programs. The increase in energy efficiency spending is recovered in rates and therefore does not impact earnings.

Taxes Other Than Income Taxes increased in 2012, as compared to 2011, due primarily to the addition of NSTAR's operations ($96.4 million). In addition, there was an increase in property taxes as a result of an increase in Property, Plant and Equipment related to our regulated capital programs and an increase in the property tax rates.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012 [a]**	**2011**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 316.9	$ 231.6	$ 85.3	36.8 %
Interest on RRBs	6.2	8.6	(2.4)	(27.9)
Other Interest	6.8	10.2	(3.4)	(33.3)
	$ 329.9	$ 250.4	$ 79.5	31.7 %

(a) The 2012 results include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012.

Interest Expense increased in 2012, as compared to 2011, due primarily to the addition of NSTAR's operations ($70.6 million). The additional increase in Interest on Long-Term Debt was a result of the $260 million in new long-term debt issuances in September 2011 and higher short-term borrowings resulting in higher interest expense.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2012 [a]**	**2011**	**Decrease**	**Percent**
Other Income, Net	$ 19.7	$ 27.7	$ (8.0)	(28.9)%

(a) The 2012 results include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012.

Other Income, Net decreased in 2012, as compared to 2011, due primarily to lower AFUDC related to equity funds at PSNH as the Clean Air Project was placed into service in September 2011, partially offset by net gains on the NU supplemental benefit trust in 2012, compared to net losses in 2011.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012 [a]**	**2011**	**Increase**	**Percent**
Income Tax Expense	$ 274.9	$ 171.0	$ 103.9	60.8%

(a) The 2012 results include the operations of NSTAR from the date of the merger, April 10, 2012, through December 31, 2012.

Income Tax Expense increased in 2012, as compared to 2011, due primarily to higher pre-tax earnings ($141.4 million), less favorable adjustments for prior year s taxes ($21.3 million) and lower items that directly impact our tax return as a result of regulatory actions (flow-through items) ($3.4 million), partially offset by Connecticut and Massachusetts settlement agreement impacts ($41 million) and merger impacts ($19.9 million).

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:				
Purchased Power, Fuel and Transmission	1,657.9	2,034.5	(376.6)	(18.5)
Operations and Maintenance	1,095.4	1,001.4	94.0	9.4
Depreciation	302.2	300.7	1.5	0.5
Amortization of Regulatory Assets, Net	91.1	90.1	1.0	1.1
Amortization of Rate Reduction Bonds	69.9	232.9	(163.0)	(70.0)
Energy Efficiency Programs	131.4	124.0	7.4	6.0
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,			
(Millions of Dollars)	**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)%
Firm Natural Gas Sales in Million Cubic Feet [(1)]	46,880	43,406	3,474	8.0 %

(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:

.

Lower electric distribution segment 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 tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. 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).

Partially offset by:

.

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

.

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.

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

(Millions of Dollars)		2011 Increase/(Decrease) Compared to 2010
Lower GSC supply costs and purchased power costs, partially offset by higher CfD and other costs at CL&P	$	(310.2)
Lower energy prices, a slight increase in ES customer migration to third party suppliers and lower retail sales for PSNH's remaining ES customers		(61.6)
Lower Basic Service costs at WMECO		(14.1)
Lower natural gas costs at Yankee Gas		(15.1)
Other and eliminations		24.4
	$	(376.6)

Operations and Maintenance increased in 2011, as compared to 2010, due primarily to:

.

Higher electric distribution expenses ($50.4 million) and higher natural gas expenses ($3.8 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. There were also 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). 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 ($17.7 million), such as uncollectible expenses and customer Energy Independence Act incentives. In addition, there were lower transmission segment expenses ($8.1 million).

.

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).

.

Higher NU parent and other companies expenses ($27.3 million) 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 then pending merger with NSTAR ($2.1 million).

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 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 at CL&P ($38.2 million) and lower amortization of the SBC balance at CL&P ($29.7 million).

Amortization of Rate Reduction Bonds 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.

Energy Efficiency Programs increased in 2011, as compared to 2010, due primarily to an increase in expenses attributable to an increase in spending in accordance with DPU approved energy efficiency programs at WMECO.

Taxes Other Than Income Taxes increased in 2011, as compared to 2010, 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 Energy Independence Act 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 year's 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 flow-through items ($4.6 million) and lower pre-tax earnings ($2.1 million); partially offset by higher state income taxes ($9.6 million).

RESULTS OF OPERATIONS THE CONNECTICUT LIGHT AND POWER 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 CL&P included in this Annual Report on Form 10-K for the years ended December 31, 2012, 2011, and 2010:

Comparison of 2012 to 2011:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 2,407.4	$ 2,548.4	$ (141.0)	(5.5)%
Operating Expenses:				
Purchased Power and Transmission	858.2	982.5	(124.3)	(12.7)
Operations and Maintenance	635.7	580.7	55.0	9.5
Depreciation	166.9	157.8	9.1	5.8
Amortization of Regulatory Assets, Net	14.4	61.0	(46.6)	(76.4)
Energy Efficiency Programs	89.3	90.3	(1.0)	(1.1)
Taxes Other Than Income Taxes	215.9	212.9	3.0	1.4
Total Operating Expenses	1,980.4	2,085.2	(104.8)	(5.0)
Operating Income	$ 427.0	$ 463.2	$ (36.2)	(7.8)%

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

	For the Years Ended December 31,			
	2012	**2011**	**Decrease**	**Percent**
Retail Sales in GWh	22,109	22,315	(206)	(0.9)%

CL&P's Operating Revenues decreased in 2012, as compared to 2011, due primarily to:

.

A $133.6 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 tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. The tracked distribution revenues decreased due primarily to lower GSC and FMCC supply-related revenues ($150.8 million), lower CTA revenues ($46.3 million), lower wholesale revenues ($33.5 million), and lower retail transmission revenues ($4.3 million). The lower GSC and FMCC supply-related revenues were due primarily to lower customer rates resulting from lower average supply prices and lower sales related to additional customer migration to third party electric suppliers in 2012. Partially offsetting these decreases were higher FMCC delivery-related revenues ($82.4 million) and higher retail SBC revenues ($22.5 million).

Partially offset by:

.

A $7.6 million increase in the portion of distribution revenues that impacts earnings in 2012, compared to 2011, due primarily to regulatory incentives of $11.5 million and C&LM incentives of $6.2 million, partially offset by lower sales volume related to warmer than normal winter weather in 2012, as compared to the winter of 2011.

.

A $7.2 million increase in transmission revenues resulting from an increased level of investment in transmission infrastructure and the recovery of higher overall expenses, which are subject to tracking mechanisms or processes (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.

Purchased Power and Transmission decreased in 2012, as compared to 2011, due primarily to the following:

(Millions of Dollars)		**2012 Increase/(Decrease) Compared to 2011**
GSC Supply Costs	$	(112.0)
Deferred Fuel Costs		(33.4)
Transmission Costs		(26.8)
Purchased Power Contracts		(19.4)
CfD Costs		70.7
Other		(3.4)
	$	(124.3)

The decrease in GSC supply costs was due to lower average supply prices and lower sales. The lower sales were due primarily to additional customer migration to third party electric suppliers. These GSC supply costs are the contractual amounts CL&P must pay to

various suppliers that have been awarded the right to supply SS and LRS load through a competitive solicitation process. These costs are included in PURA approved tracking mechanisms and do not impact earnings.

Operations and Maintenance increased in 2012, as compared to 2011, due primarily to the establishment of a reserve related to major storm restoration costs ($40 million) and a bill credit to customers ($25 million) in the second quarter of 2012 as a result of the Connecticut settlement agreement**.** In addition, there were higher distribution business expenses as a result of higher general and administrative expenses primarily related to an increase in pension costs ($20.2 million) and higher routine distribution maintenance ($19.4 million). There were also higher distribution costs related to customer Energy Independence Act incentives, which are tracked and fully recoverable through tracking mechanisms ($6.5 million). Partially offsetting these increases was the absence in 2012 of the storm fund reserve established in 2011 to provide bill credits to residential customers as a result of the October 2011 snowstorm ($30 million) and a decrease in the amortization of the regulatory deferral allowed in the 2010 rate case decision ($21.4 million).

Depreciation increased in 2012, as compared to 2011, due primarily to higher utility plant balances resulting from completed construction projects placed into service related to CL&P s capital programs.

Amortization of Regulatory Assets, Net decreased in 2012, as compared to 2011, due primarily to higher CTA transition costs ($21.5 million) and lower CTA revenues ($46.3 million). Partially offsetting these impacts were lower SBC costs ($7.6 million) and higher retail SBC revenues ($22.5 million).

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 124.9	$ 131.9	$ (7.0)	(5.3)%
Other Interest	8.2	0.8	7.4	(a)
	$ 133.1	$ 132.7	$ 0.4	0.3 %

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

Interest on Long-Term Debt decreased in 2012, as compared to 2011, due primarily to the refinancing of the PCRBs at a lower interest rate in October 2011. Other Interest increased in 2012, as compared to 2011, due primarily to the absence of tax-related benefits recognized in 2011 and an increase in short-term borrowings resulting in higher interest expense.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase**	**Percent**
Income Tax Expense	$ 94.4	$ 90.0	$ 4.4	4.9%

Income Tax Expense increased in 2012, as compared to 2011, due primarily to less favorable adjustments for prior year s taxes ($22.4 million), an increase to pre-tax earnings ($13.8 million), partially offset by Connecticut settlement agreement impacts ($26.6 million), and lower state tax and other impacts ($5.2 million).

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	$	2,548.4	$	2,999.1	$	(450.7)	(15.0)%
Operating Expenses:							
Purchased Power and Transmission		982.5		1,292.7		(310.2)	(24.0)
Operations and Maintenance		580.7		494.2		86.5	17.5
Depreciation		157.8		172.1		(14.3)	(8.4)
Amortization of Regulatory Assets, Net		61.0		78.9		(17.9)	(22.7)
Amortization of Rate Reduction Bonds		-		167.0		(167.0)	(100.0)
Energy Efficiency Programs		90.3		92.3		(2.0)	(2.2)
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:

.

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.

.

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.

Partially offset by:

.

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.

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

(Millions of Dollars)		**2011 Increase/(Decrease) Compared to 2010**
GSC Supply Costs	$	(325.8)
Purchased Power Costs		(60.4)
CfD Costs		54.9
Transmission Costs		13.2
Deferred Fuel Costs		10.5
Other		(2.6)
	$	(310.2)

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.

Operations and Maintenance increased in 2011, as compared to 2010, as a result of higher distribution expenses ($60.4 million). Included in these costs was 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, higher general and administrative expenses, including higher pension costs. In addition, there was an increase related 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). Partially offsetting these increases were lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($16.4 million) and lower transmission segment expenses ($7.4 million).

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 decreased in 2011, as compared to 2010, due primarily to lower amortization related to the previously deferred unrecovered stranded generation costs ($38.2 million) and lower amortization of the SBC balance ($29.7 million). Partially offsetting these decreases were lower CTA transition costs ($197.7 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 Reductions Bonds decreased in 2011, as compared to 2010, due to the maturity of RRBs in December 2010.

Taxes Other Than Income Taxes decreased in 2011, as compared to 2010, 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 Energy Independence Act 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 year s 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).

LIQUIDITY

CL&P had cash flows provided by operating activities of $211.9 million in 2012, compared with cash flows provided by operating activities of $513.3 million in 2011. The reduced cash flows were due primarily to $223.1 million of cash disbursements for storm restoration costs primarily associated with Tropical Storm Irene, the October 2011 snowstorm, and Hurricane Sandy made in 2012, as compared to approximately $132 million in 2011, $27 million in bill credits provided to residential customers in February 2012 related to the October 2011 snowstorm, $25 million in bill credits to customers associated with the Connecticut settlement agreement and changes in traditional working capital amounts principally due to the changes in the timing of payments of accounts payable and accrued liabilities. In addition, CL&P had lower recovery of its deferred operation and maintenance costs of $23.1 million in 2012, as

compared to 2011, a negative cash flow impact of $38.9 million resulting from changes in reserves for transmission refunds in 2012, as compared to 2011, and a decrease in income tax refunds of $14.6 million in 2012, as compared to 2011.

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 PURA July 1, 2010 distribution rate case decision, which increased CL&P s customer rates effective January 1, 2011, and income tax receipts 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 for storm restoration costs associated with Tropical Storm Irene and the October 2011 snowstorm.

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 $449.1 million in 2012, compared with $424.9 million in 2011.

On March 22, 2012, the FERC approved CL&P's application requesting to increase its total short-term borrowing capacity from a maximum of $450 million to a maximum of $600 million through December 31, 2013.

On March 26, 2012, CL&P entered into a five-year $300 million unsecured revolving credit facility. The credit facility is intended to finance short-term borrowings that CL&P incurred to fund costs of restoring power following Tropical Storm Irene and the October 2011 snowstorm. Under this new facility, CL&P can borrow either on a short-term or a long-term basis subject to any necessary regulatory approval, and may borrow at prime rates or LIBOR-based rates, plus an applicable margin based on the higher of S&P s or Moody s credit ratings. As of December 31, 2012, CL&P had $89 million in borrowings outstanding under this credit facility. The weighted-average interest rate on these borrowings as of December 31, 2012 was 3.325 percent.

On April 2, 2012, CL&P remarketed $62 million of tax-exempt PCRBs that were subject to mandatory tender on that date. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.55 percent during the current three-year fixed-rate period, and are subject to mandatory tender for purchase on April 1, 2015.

On July 25, 2012, NU, CL&P, NSTAR LLC, NSTAR Gas, PSNH, WMECO, and Yankee Gas jointly entered into a five-year $1.15 billion revolving credit facility. The new facility replaced (1) the NSTAR LLC revolving credit facility of $175 million that served to backstop a commercial paper program utilized by NSTAR LLC and was scheduled to expire on December 31, 2012, (2) the NSTAR Gas revolving credit facility of $75 million that expired on June 8, 2012, and (3) the CL&P, PSNH, WMECO, and Yankee Gas joint $400 million and NU parent $500 million unsecured revolving credit facilities that were scheduled to expire on September 24, 2013. The new facility expires on July 25, 2017. As of December 31, 2012, CL&P had $405.1 million in intercompany short-term borrowings under the NU commercial paper program. The weighted average interest rate on these borrowings as of December 31, 2012 was 0.46 percent.

On October 1, 2012, CL&P redeemed at par four different series of tax-exempt PCRBs totaling $116.4 million. The PCRBs carried coupons that ranged from 5.85 percent to 5.95 percent and maturities that ranged from 2016 through 2028.

On January 15, 2013, CL&P issued $400 million of 2.5 percent first mortgage bonds that will mature on January 15, 2023. The proceeds, net of issuance costs, were used to repay CL&P s revolving credit facility borrowings of $89 million and $305.8 million of its commercial paper program borrowings.

Financing activities in 2012 included $100.5 million in common stock dividends paid to NU parent, an increase in intercompany short-term borrowings of $346.6 million, and an increase in short-term notes payable of $58 million.

CL&P uses available capital resources to fund its construction expenditures, meet debt requirements, pay costs, including storm-related costs, pay dividends and fund its other obligations. The current growth in CL&P s transmission construction expenditures utilizes a significant amount of cash for projects that have a long-term return on investment and recovery period. In addition, CL&P operates in an environment where recovery of its distribution construction expenditures takes place over an extended period of time. As well, the future recovery of its deferred storm-related costs, which must be approved by the PURA, will take place over a six-year period for those costs deferred as a result of 2011 activity (as covered by the Connecticut Settlement Agreement) and over an extended period of time for those storm restoration costs incurred related to Hurricane Sandy. This impacts the timing of the revenue stream designed to fully recover the total investment plus a return on the equity portion of the cost and related financing costs. These factors have resulted in CL&P s current liabilities exceeding current assets by approximately $268 million as of December 31, 2012.

As of December 31, 2012, $125 million of CL&P's current liabilities relates to long-term debt that will be paid in the next 12 months. CL&P, with its strong credit ratings, has several options available in the financial markets to repay or refinance these maturities with the issuance of new long-term debt. CL&P will reduce its short-term borrowings with cash received from operating cash flows or with the issuance of new long-term debt, as deemed appropriate given our capital requirements and maintenance of our credit rating and profile. Management expects the future operating cash flows of CL&P, along with the access to financial markets, will be sufficient to meet any future operating requirements and capital investment forecasted opportunities.

RESULTS OF OPERATIONS   NSTAR ELECTRIC 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 NSTAR Electric included in this Annual Report on Form 10-K for the years ended December 31, 2012, 2011, and 2010:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 2,301.0	$ 2,403.1	$ (102.1)	(4.2)%
Operating Expenses:				
Purchased Power and Transmission	788.3	905.2	(116.9)	(12.9)
Operations and Maintenance	431.8	387.5	44.3	11.4
Depreciation	171.1	163.4	7.7	4.7
Amortization of Regulatory Assets, Net	117.7	83.0	34.7	41.8
Amortization of Rate Reduction Bonds	90.3	90.3	-	-
Energy Efficiency Programs	201.2	175.7	25.5	14.5
Taxes Other Than Income Taxes	119.2	111.8	7.4	6.6
Total Operating Expenses	1,919.6	1,916.9	2.7	0.1
Operating Income	$ 381.4	$ 486.2	$ (104.8)	(21.6)%

Operating Revenues

NSTAR Electric's retail sales were as follows:

	For the Years Ended December 31,			
	2012	**2011**	**Decrease**	**Percent**
Retail Sales in GWh	21,209	21,502	(293)	(1.4)%

NSTAR Electric's Operating Revenues decreased in 2012, as compared to 2011, due primarily to:

.

A $104.7 million decrease in distribution revenues related to the portions that are included in DPU approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. This decrease primarily related to lower purchased power and transmission costs ($34.2 million), lower retail transmission revenues ($19.8 million), lower PAM revenues ($19.1 million), lower transition revenues

($14.7 million), partially offset by an increase in energy efficiency program revenues ($8.3 million).

Partially offset by:

.

A $2.8 million increase in transmission revenues resulting from an increased 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.

Purchased Power and Transmission decreased in 2012, as compared to 2011, due primarily to the following:

(Millions of Dollars)		**2012 Increase/(Decrease) Compared to 2011**
Basic Service Costs	$	(53.8)
Purchased Power Contracts		(45.5)
Transmission Costs		(29.6)
Deferred Fuel Costs		15.7
Other		(3.7)
	$	(116.9)

The decrease in Basic Service costs was due primarily to lower average supply prices and additional customer migration to third party electric suppliers and the decrease in purchased power contracts was due primarily to the expiration of certain contracts. The decrease in transmission costs was due primarily to a lower transmission cost deferral that will be recovered in future periods. The increase in deferred fuel costs was due primarily to lower average supply prices, as compared to the prices projected when Basic Service rates were set. These costs are included in DPU approved tracking mechanisms and do not impact earnings.

Operations and Maintenance increased in 2012, as compared to 2011, due primarily to the cumulative adjustment recorded to establish a reserve against the regulatory asset related to Basic Service bad debt costs ($28 million). In addition, first quarter 2012 adjustments were recognized for changes in accounting estimates related primarily to the allowance for doubtful accounts, workers compensation, employee medical benefits, and general liability claims ($18.7 million). In addition, a bill credit to customers ($15 million) was recorded in the second quarter of 2012 as a result of the Massachusetts settlement agreement. Also contributing to the increase in costs was an incident in March 2012 involving a substation fire in the Back Bay/Prudential area of Boston ($11.8 million). These increases were partially offset by lower PAM-related amortizations ($23.1 million).

Amortization of Regulatory Assets, Net, increased in 2012, as compared to 2011, due primarily to higher amortization related to transition costs.

Energy Efficiency Programs increased in 2012, as compared to 2011, due primarily to the establishment of a reserve to reflect a billing adjustment made in the fourth quarter of 2012, and an increase in energy efficiency costs in accordance with the three-year program guidelines established by the DPU. All costs are fully recovered through DPU tracking mechanisms and therefore do not impact earnings.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 87.1	$ 90.0	$ (2.9)	(3.2)%
Interest on RRBs	3.6	7.2	(3.6)	(50.0)
Other Interest	(20.6)	(27.8)	7.2	25.9
	$ 70.1	$ 69.4	$ 0.7	1.0 %

Other Interest expense increased in 2012, as compared to 2011, due primarily to a reduction in regulatory interest income primarily from deferred transition costs ($5.9 million) and reduced interest income from legal matters ($3.2 million), partially offset by a decrease in the interest expense related to tax issues ($2 million) due to the receipt of a 2001 through 2007 tax settlement in June 2011.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Decrease**	**Percent**

Income Tax Expense	$	124.0	$	165.7	$	(41.7)	(25.2)%

Income Tax Expense decreased in 2012, as compared to 2011, due primarily to lower pre-tax earnings ($33.6 million), Massachusetts settlement agreement impacts ($5.9 million) and merger impacts ($1.2 million).

EARNINGS SUMMARY

	For the Years Ended December 31,					
(Millions of Dollars)		**2012**		**2011**		**2010**
Income Before Merger Settlement Agreement Costs	$	201.1	$	252.5	$	248.6
Merger Settlement Agreement Costs (after-tax)		(10.9)		-		-
Net Income	$	190.2	$	252.5	$	248.6

The after-tax merger settlement agreement costs in 2012 consisted of approximately $17.9 million (pre-tax) of charges for customer bill credits related to the Massachusetts settlement agreement, transaction and integration-related costs, and compensation costs.

Excluding the merger settlement agreement costs, NSTAR Electric s 2012 earnings were $51.4 million lower than 2011 due primarily to the first quarter 2012 adjustments recorded to establish a reserve against the regulatory asset related to Basic Service bad debt costs ($17 million), and for changes in accounting estimates related primarily to the allowance for doubtful accounts, workers compensation, employee medical benefits, and general liability claims ($11.4 million). Also contributing to the increase in costs was an incident in March 2012 involving a substation fire in the Back Bay/Prudential area of Boston ($7.2 million), a reserve recorded relating to lost base revenues based on developments during hearings in the merger proceeding ($3 million) and higher depreciation and property taxes ($17.3 million). These factors are partially offset by higher transmission revenues due to an increased level of investment in transmission infrastructure ($6.2 million).

NSTAR Electric s 2011 earnings were $252.5 million, compared to $248.6 million in 2010. Major factors on an after-tax basis that contributed to the $3.9 million, increase include:

.

higher transmission revenues ($10.9 million);

.

higher lost base revenues and performance incentives related to the impacts of the Energy Efficiency Programs ($7 million); and

.

the absence in 2011 of the cumulative impact of a true-up adjustment resulting from a DPU order in May 2010 related to NSTAR Electric s transition revenue for the years 2006 through 2009 ($3 million).

These increases were partially offset by:

.

lower distribution revenues (0.7 percent decrease in sales) due to cooler summer weather in 2011, as compared to the summer of 2010, and the impact of energy conservation programs ($5.4 million);

.

higher depreciation and property taxes ($7.3 million); and

.

higher operations and maintenance expenses ($8.8 million).

CAPITAL EXPENDITURES

A summary of capital expenditures, including amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portions of pension and PBOP expense or income, is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2012**	**2011**	**2010**
Transmission	$ 192.1	$ 162.5	$ 87.2
Distribution:			
Basic Business	64.2	58.5	54.7
Aging Infrastructure	145.8	132.8	124.2
Load Growth	21.2	19.3	18.0
Total Distribution	231.2	210.6	196.9
Total	$ 423.3	$ 373.1	$ 284.1

LIQUIDITY

NSTAR Electric had cash flows provided by operating activities of $506.9 million in 2012 and $662 million in 2011 (amounts are net of RRB payments, which are included in financing activities). The decreased cash flows in 2012 were due primarily to the absence in 2012 of income tax refunds received during 2011. In 2012, NSTAR Electric made income tax payments of $88.1 million, as compared to income tax refunds of $62.2 million in 2011. In addition, NSTAR Electric provided $15 million in bill credits to its customers associated with the Massachusetts settlement agreement in 2012, and had regulatory undercollections of retail transmission revenues of $53 million in 2012, as compared to 2011. Partially offsetting these negative cash flow impacts was a reduction in Pension Plan contributions of $100 million in 2012, as compared to 2011.

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, 2012 and 2011:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 988.0	$ 1,013.0	$ (25.0)	(2.5)%
Operating Expenses:				
Purchased Power, Fuel and Transmission	319.3	327.9	(8.6)	(2.6)
Operations and Maintenance	263.2	278.2	(15.0)	(5.4)
Depreciation	87.6	76.1	11.5	15.1
Amortization of Regulatory Assets/(Liabilities), Net	(24.1)	25.4	(49.5)	(a)
Amortization of Rate Reduction Bonds	56.6	53.4	3.2	6.0
Energy Efficiency Programs	14.2	12.9	1.3	10.1
Taxes Other Than Income Taxes	66.1	59.0	7.1	12.0
Total Operating Expenses	782.9	832.9	(50.0)	(6.0)
Operating Income	$ 205.1	$ 180.1	$ 25.0	13.9 %

(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,			
	2012	**2011**	**Increase**	**Percent**
Retail Sales in GWh	7,821	7,815	6	0.1 %

PSNH's Operating Revenues decreased in 2012, as compared to 2011, due primarily to:

.

A $52.7 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. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. This decrease related primarily to lower purchased power and fuel costs ($88.3 million), lower wholesale revenues ($7.3 million) and lower retail transmission revenues ($5.8 million). These lower revenues were partially offset by higher SCRC revenues ($34.2 million) and RECs ($9.5 million).

Partially offset by:

.

An increase related to the sale of oil to a third party ($20.8 million) in the second quarter of 2012, resulting in a benefit to customers through lower ES rates that does not impact earnings.

.

A $9.9 million increase in transmission revenues resulting from an increased 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.

.

A $3.5 million increase in the portion of distribution revenues that impacts earnings in 2012, as compared to 2011, due primarily to the favorable impact of the 2010 rate case decision related to the additional increase to annualized rates that was effective July 1, 2012.

Purchased Power, Fuel and Transmission decreased in 2012, as compared to 2011, due primarily to a decrease in purchased power costs, partially offset by an increase in transmission costs. The decrease in purchased power costs was due primarily to lower market prices in 2012, as compared to 2011, as well as an increase in ES customer migration to third party suppliers.

Operations and Maintenance decreased in 2012, as compared to 2011, as a result of lower maintenance costs at the generation business due to less planned outage maintenance in 2012 ($17.8 million), partially offset by higher distribution general and administrative costs ($3 million).

Depreciation increased in 2012, as compared to 2011, 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 decreased in 2012, as compared to 2011, due primarily to a decrease in ES and TCAM amortization ($46.9 million and $20.2 million, respectively), partially offset by an increase in SCRC amortization ($13.5 million).

Taxes Other Than Income Taxes increased in 2012, as compared to 2011, 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 property tax rates.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 46.2	$ 36.8	$ 9.4	25.5 %
Interest on RRBs	2.7	6.3	(3.6)	(57.1)
Other Interest	1.3	1.0	0.3	30.0
	$ 50.2	$ 44.1	$ 6.1	13.8 %

Interest Expense increased in 2012, as compared to 2011, due primarily to an increase in Interest on Long-Term Debt, which was primarily the result of a reduction in AFUDC related to borrowed funds as the Clean Air Project was placed into service in September 2011 ($5.5 million). The additional increase in Interest on Long-Term Debt was a result of the $160 million long-term debt issuance in September 2011.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Decrease**	**Percent**
Other Income, Net	$ 3.0	$ 14.3	$ (11.3)	(79.0)%

Other Income, Net decreased in 2012, as compared to 2011, due primarily to lower AFUDC related to equity funds as the Clean Air Project was placed into service in September 2011.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase**	**Percent**
Income Tax Expense	$ 61.0	$ 49.9	$ 11.1	22.2%

Income Tax Expense increased in 2012, as compared to 2011, due primarily to lower flow-through items ($4.1 million), higher state taxes ($3.8 million), an increase in pre-tax earnings ($2.7 million) and return to provision ($0.8 million).

LIQUIDITY

PSNH had cash flows provided by operating activities in 2012 of $174.2 million, compared with operating cash flows of $151.8 million in 2011 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows in 2012 were due primarily to a reduction in NU Pension Plan contributions of $24.9 million in 2012, as compared to 2011, the absence in 2012 of a cash flow hedge settlement creating a favorable cash flow impact of $18.1 million, and an increased reduction in coal and fuel inventories in 2012. The reduction in fuel inventories in 2012 is primarily attributable to the sale of oil to a third party for $20.8 million. Offsetting these positive cash flow impacts were income tax payments in 2012 of $14.7 million, as compared to income tax refunds in 2011 of $29.3 million.

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, 2012 and 2011:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 441.2	$ 417.3	$ 23.9	5.7 %
Operating Expenses:				
Purchased Power and Transmission	136.1	161.5	(25.4)	(15.7)
Operations and Maintenance	97.0	80.2	16.8	20.9
Depreciation	30.0	26.5	3.5	13.2
Amortization of Regulatory Assets, Net	0.4	4.5	(4.1)	(91.1)
Amortization of Rate Reduction Bonds	17.6	16.5	1.1	6.7
Energy Efficiency Programs	27.8	21.8	6.0	27.5
Taxes Other Than Income Taxes	21.5	17.9	3.6	20.1
Total Operating Expenses	330.4	328.9	1.5	0.5
Operating Income	$ 110.8	$ 88.4	$ 22.4	25.3 %

Operating Revenues

WMECO's retail sales were as follows:

	For the Years Ended December 31,			
	2012	**2011**	**Decrease**	**Percent**
Retail Sales in GWh	3,683	3,695	(12)	(0.3)%

WMECO's Operating Revenues increased in 2012, as compared to 2011, due primarily to:

.

A $32.3 million increase in transmission revenues resulting from an increased level of investment in transmission infrastructure, primarily related to the NEEWS projects, 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.

.

An increase in the portion of distribution revenues that impacts earnings related to the absence in 2012 of the establishment of a reserve related to a wholesale billing adjustment in the third quarter of 2011 ($5 million).

Partially offset by:

.

A $5.2 million decrease in distribution revenues related to the portions that are included in DPU approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. Included in these amounts are Basic Service, pension, transition and energy efficiency program costs.

Purchased Power and Transmission decreased in 2012, as compared to 2011, due primarily to lower purchased transmission costs ($14 million), lower Basic Service costs ($7 million) and lower purchased power costs ($3.4 million).

Operations and Maintenance increased in 2012, as compared to 2011, due to an increase in distribution business expenses primarily related to higher pension costs ($3.9 million), which are recovered through DPU approved tracking mechanisms and have no earnings impact. There were also higher routine distribution overhead line maintenance costs ($2.7 million), higher transmission operating costs ($2 million) and higher uncollectible expenses ($1.9 million). In addition, there was a bill credit to customers ($3 million) in the second quarter of 2012 as a result of the Massachusetts settlement agreement.

Depreciation increased in 2012, as compared to 2011, 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, Net decreased in 2012, as compared to 2011, due primarily to a decrease in amortization of the transition charge deferral.

Energy Efficiency Programs increased in 2012, as compared to 2011, due primarily to an increase in expenses attributable to an increase in spending in accordance with DPU approved energy efficiency programs. The increase in energy efficiency spending is recovered in rates and therefore does not impact earnings.

Taxes Other Than Income Taxes increased in 2012, as compared to 2011, due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to WMECO s capital program and an increase in the property tax rates.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 23.5	$ 20.0	$ 3.5	17.5 %
Interest on RRBs	1.2	2.3	(1.1)	(47.8)
Other Interest	1.9	1.3	0.6	46.2
	$ 26.6	$ 23.6	$ 3.0	12.7 %

Interest Expense increased in 2012, as compared to 2011, due primarily to higher Interest on Long-Term Debt resulting from a $100 million long-term debt issuance in September 2011 and a $150 million long-term debt issuance on October 4, 2012.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2012**	**2011**	**Increase**	**Percent**
Income Tax Expense	$ 32.1	$ 23.2	$ 8.9	38.4%

Income Tax Expense increased in 2012, as compared to 2011, due primarily to higher pre-tax earnings ($9.2 million) and higher state taxes ($2.4 million), partially offset by Massachusetts settlement agreement impacts ($1.2 million) and a regulatory decision that reduced a non-plant flow through difference ($1.3 million).

LIQUIDITY

WMECO had cash flows provided by operating activities in 2012 of $77 million, compared with operating cash flows of $108 million in 2011 (amounts are net of RRB payments, which are included in financing activities). The reduced cash flows in 2012 were due primarily to unfavorable cash flow impacts of $6.6 million relating to C&LM and $16.1 million relating to the change in transmission regulatory tracking mechanisms. In addition, WMECO paid $3 million in bill credits to customers in 2012 associated with the Massachusetts settlement agreement.

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 December 31, 2013 with an agency comprised of municipalities and related purchase agreements. We have not entered into any energy contracts for trading purposes. 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. For Select Energy's wholesale energy portfolio derivatives, we utilize the sensitivity analysis methodology to disclose quantitative information of the potential loss of future pre-tax earnings for one or more hypothetical changes in commodity price components. A hypothetical 30 percent increase or decrease in forward energy, ancillary or capacity prices would not have a material impact on earnings**.** 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: As of December 31, 2012, approximately 91 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 $8.7 million.

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, 2012, our Regulated companies did not hold cash collateral from counterparties. As of December 31, 2012, NU had cash posted with ISO-NE related to energy purchase transactions. In addition, Select Energy has also established written credit policies with regard to its counterparties to minimize overall credit risk on its remaining contracts. These policies require collateral under certain circumstances (including cash in advance 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.

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 1G, "Summary of Significant Accounting Policies - Restricted Cash and Other Deposits," and Note 5, "Derivative Instruments," to the consolidated financial statements.

If the respective unsecured debt ratings of NU or its subsidiaries were reduced to below investment grade by either Moody s or S&P, certain of NU s contracts would require additional collateral in the form of cash to be provided to counterparties and independent system operators. NU would have been and remains able to provide that collateral.

Item 8.

Financial Statements and Supplementary Data

Company Report on Internal Controls Over Financial Reporting

Northeast Utilities

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, 2012.

Management has excluded from our assessment of and conclusion on the effectiveness of internal controls over financial reporting the internal controls of NSTAR LLC, acquired on April 10, 2012, which is included in the consolidated financial statements of the Company as of and for the year ended December 31, 2012, constituting $11.3 billion and $5.1 billion of total and net assets, respectively, as of December 31, 2012, and $1,957.8 million and $182.9 million of revenues and net income attributable to controlling interest, respectively, for the period from April 10, 2012 through December 31, 2012.

February 27, 2013

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, 2012 and 2011, 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, 2012. 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, 2012, 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.

As described in the Company Report on Internal Controls Over Financial Reporting, management excluded from its assessment the internal control over financial reporting at NSTAR LLC and its subsidiaries, the post-merger parent company of NSTAR and its subsidiaries, which was acquired on April 10, 2012 and whose financial statements constitute 55 percent and 40 percent of net and total assets, respectively, 31 percent of revenues, and 35 percent of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2012. Accordingly, our audit did not include the internal control over financial reporting at NSTAR LLC and its subsidiaries.

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 Northeast Utilities and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 2, "Merger of NU and NSTAR," to the consolidated financial statements, on April 10, 2012, the Company acquired NSTAR and its subsidiaries.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 27, 2013

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

		As of December 31,		
(Thousands of Dollars)		2012		2011
ASSETS				
Current Assets:				
Cash and Cash Equivalents	$	45,748	$	6,559
Receivables, Net		792,822		488,002
Unbilled Revenues		216,040		175,207
Fuel, Materials and Supplies		267,713		248,958
Regulatory Assets		705,025		255,144
Marketable Securities		91,975		70,970
Prepayments and Other Current Assets		107,972		112,632
Total Current Assets		2,227,295		1,357,472
Property, Plant and Equipment, Net		16,605,010		10,403,065
Deferred Debits and Other Assets:				
Regulatory Assets		5,132,411		3,267,710
Goodwill		3,519,401		287,591
Marketable Securities		400,329		60,311
Derivative Assets		90,612		98,357
Other Long-Term Assets		327,766		172,560
Total Deferred Debits and Other Assets		9,470,519		3,886,529
Total Assets	$	28,302,824	$	15,647,066

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

76

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2012	2011
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable	$ 1,120,196	$ 317,000
Long-Term Debt - Current Portion	763,338	331,582
Accounts Payable	764,350	633,282
Regulatory Liabilities	134,115	167,844
Derivative Liabilities	117,194	107,558
Other Current Liabilities	744,497	390,416
Total Current Liabilities	3,643,690	1,947,682
Rate Reduction Bonds	82,139	112,260
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	3,463,347	1,868,316
Regulatory Liabilities	540,162	266,145
Derivative Liabilities	882,654	959,876
Accrued Pension, SERP and PBOP	2,130,497	1,326,037
Other Long-Term Liabilities	967,561	420,011
Total Deferred Credits and Other Liabilities	7,984,221	4,840,385
Capitalization:		
Long-Term Debt	7,200,156	4,614,913
Noncontrolling Interest - Preferred Stock of Subsidiaries	155,568	116,200
Equity:		
Common Shareholders' Equity:		
Common Shares	1,662,547	980,264
Capital Surplus, Paid In	6,183,267	1,797,884
Retained Earnings	1,802,714	1,651,875
Accumulated Other Comprehensive Loss	(72,854)	(70,686)
Treasury Stock	(338,624)	(346,667)
Common Shareholders' Equity	9,237,050	4,012,670
Noncontrolling Interests	-	2,956
Total Equity	9,237,050	4,015,626

Total Capitalization		16,592,774		8,746,739
Commitments and Contingencies (Note 12)				
Total Liabilities and Capitalization	$	28,302,824	$	15,647,066

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)	2012	2011	2010
Operating Revenues	$ 6,273,787	$ 4,465,657	$ 4,898,167
Operating Expenses:			
Purchased Power, Fuel and Transmission	2,084,364	1,657,914	2,034,501
Operations and Maintenance	1,583,070	1,095,358	1,001,349
Depreciation	519,010	302,192	300,737
Amortization of Regulatory Assets, Net	79,762	91,080	90,054
Amortization of Rate Reduction Bonds	142,019	69,912	232,871
Energy Efficiency Programs	313,149	131,415	124,023
Taxes Other Than Income Taxes	434,207	323,610	314,741
Total Operating Expenses	5,155,581	3,671,481	4,098,276
Operating Income	1,118,206	794,176	799,891
Interest Expense:			
Interest on Long-Term Debt	316,987	231,630	231,089
Interest on Rate Reduction Bonds	6,168	8,611	20,573
Other Interest	6,790	10,184	(14,371)
Interest Expense	329,945	250,425	237,291
Other Income, Net	19,742	27,715	41,916
Income Before Income Tax Expense	808,003	571,466	604,516
Income Tax Expense	274,926	170,953	210,409
Net Income	533,077	400,513	394,107
Net Income Attributable to Noncontrolling Interests	7,132	5,820	6,158
Net Income Attributable to Controlling Interest	$ 525,945	$ 394,693	$ 387,949
Basic Earnings Per Common Share	$ 1.90	$ 2.22	$ 2.20
Diluted Earnings Per Common Share	$ 1.89	$ 2.22	$ 2.19
Weighted Average Common Shares Outstanding:			
Basic	277,209,819	177,410,167	176,636,086
Diluted	277,993,631	177,804,568	176,885,387

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, 2012	2011	2010
Net Income	$ 533,077	$ 400,513	$ 394,107
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	1,971	(14,177)	200
Changes in Unrealized Gains on Other Securities	217	506	402
Change in Funded Status of Pension, SERP and PBOP Benefit Plans	(4,356)	(13,645)	(505)
Other Comprehensive Income/(Loss), Net of Tax	(2,168)	(27,316)	97
Comprehensive Income Attributable to Noncontrolling Interests	(7,132)	(5,820)	(6,158)
Comprehensive Income Attributable to Controlling Interest	$ 523,777	$ 367,377	$ 388,046

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		Capital Surplus,	Deferred Contribution	Retained	Accumulated Other Comprehensive	Treasury	Total Common Shareholders'
	Shares	Amount	Paid In	Plan	Earnings	Income/(Loss)	Stock	Equity
Balance as of January 1, 2010	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)
Dividends on Preferred Stock					(6,101)			(6,101)
Issuance of Common Shares, $5 Par Value	326,526	1,633	5,745					7,378
Allocation of Benefits - ESOP	127,054		439	2,944				3,383
Long-Term Incentive Plan Activity			4,868					4,868
Issuance of Treasury Shares to Fund ESOP	374,477		3,856				6,871	10,727
Other Changes in Shareholders' Equity			587					587
Net Income Attributable to Noncontrolling Interests					(57)			(57)
Other Comprehensive Income						97		97
	176,448,081	978,909	1,777,592	-	1,452,777	(43,370)	(354,732)	3,811,176

Balance as of December 31, 2010								
Net Income					400,513			400,513
Dividends on Common Shares - $1.10 Per Share					(195,595)			(195,595)
Dividends on Preferred Stock					(5,559)			(5,559)
Issuance of Common Shares, $5 Par Value	271,030	1,355	4,496					5,851
Long-Term Incentive Plan Activity			7,359					7,359
Issuance of Treasury Shares to Fund ESOP	439,581		7,048				8,065	15,113
Other Changes in Shareholders' Equity			1,389					1,389
Net Income Attributable to Noncontrolling Interests					(261)			(261)
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
Net Income					533,077			533,077
Shares Issued in Connection with NSTAR Merger	136,048,595	680,243	4,358,027					5,038,270
Other Equity Impacts of Merger with NSTAR			2,938		421			3,359
Dividends on Common Shares - $1.32 Per Share					(375,527)			(375,527)
Dividends on Preferred Stock					(7,029)			(7,029)
Issuance of Common Shares, $5 Par Value	408,018	2,040	11,287					13,327
			(3,897)					(3,897)

Long-Term Incentive Plan Activity								
Issuance of Treasury Shares to Fund ESOP	438,329		8,454				8,043	16,497
Other Changes in Shareholders' Equity			8,574					8,574
Net Income Attributable to Noncontrolling Interests					(103)			(103)
Other Comprehensive Loss						(2,168)		(2,168)
Balance as of December 31, 2012	314,053,634	$ 1,662,547	$ 6,183,267	$ -	$ 1,802,714	$ (72,854)	$ (338,624)	$ 9,237,050

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2012	2011	2010
Operating Activities:			
Net Income	$ 533,077	$ 400,513	$ 394,107
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	36,275	16,420	31,352
Depreciation	519,010	302,192	300,737
Deferred Income Taxes	292,000	196,761	210,939
Pension, SERP and PBOP Expense	218,540	133,000	103,861
Pension and PBOP Contributions	(295,028)	(191,101)	(90,633)
Regulatory (Under)/Over Recoveries, Net	(259,853)	(70,863)	26,289
Amortization of Regulatory Assets, Net	79,762	91,080	90,054
Amortization of Rate Reduction Bonds	142,019	69,912	232,871
Derivative Assets and Liabilities	(10,455)	(35,441)	(11,812)
Other	17,032	(29,751)	(72,151)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(20,214)	17,570	(51,285)
Fuel, Materials and Supplies	34,321	(11,033)	38,126
Taxes Receivable/Accrued, Net	(5,450)	49,642	(82,103)
Accounts Payable	(128,339)	18,916	(44,355)
Other Current Assets and Liabilities, Net	8,532	12,569	17,466
Net Cash Flows Provided by Operating Activities	1,161,229	970,386	1,093,463
Investing Activities:			
Investments in Property, Plant and Equipment	(1,472,272)	(1,076,730)	(954,472)
Proceeds from Sales of Marketable Securities	317,294	149,441	174,865
Purchases of Marketable Securities	(348,629)	(151,972)	(177,204)
Proceeds from Sale of Assets	-	46,841	-
Other Investing Activities	35,683	13,833	(1,157)
Net Cash Flows Used in Investing Activities	(1,467,924)	(1,018,587)	(957,968)

Financing Activities:						
Cash Dividends on Common Shares		(375,047)		(194,555)		(180,542)
Cash Dividends on Preferred Stock		(7,029)		(5,559)		(5,559)
Increase in Short-Term Debt		825,000		50,000		166,687
Issuance of Long-Term Debt		850,000		627,500		145,000
Retirements of Long-Term Debt		(839,136)		(369,586)		(4,286)
Retirements of Rate Reduction Bonds		(114,433)		(69,312)		(260,864)
Other Financing Activities		6,529		(7,123)		512
Net Cash Flows Provided by/(Used in) Financing Activities		345,884		31,365		(139,052)
Net Increase/(Decrease) in Cash and Cash Equivalents		39,189		(16,836)		(3,557)
Cash and Cash Equivalents - Beginning of Year		6,559		23,395		26,952
Cash and Cash Equivalents - End of Year	$	45,748	$	6,559	$	23,395

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

Company Report on Internal Controls Over Financial Reporting

The Connecticut Light and Power Company

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of The Connecticut Light and Power Company and subsidiary (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, 2012.

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of The Connecticut Light and Power Company:

We have audited the accompanying consolidated balance sheets of The Connecticut Light and Power Company and subsidiary (the "Company") as of December 31, 2012 and 2011, 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, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of The Connecticut Light and Power Company and subsidiary as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 27, 2013

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2012	2011
ASSETS		
Current Assets:		
Cash	$ 1	$ 1
Receivables, Net	284,787	295,028
Accounts Receivable from Affiliated Companies	6,641	1,548
Unbilled Revenues	85,353	94,995
Regulatory Assets	185,858	170,197
Materials and Supplies	64,603	61,102
Prepayments and Other Current Assets	26,413	53,920
Total Current Assets	653,656	676,791
Property, Plant and Equipment, Net	6,152,959	5,827,384
Deferred Debits and Other Assets:		
Regulatory Assets	2,158,363	2,103,830
Derivative Assets	90,612	93,755
Other Long-Term Assets	86,498	89,636
Total Deferred Debits and Other Assets	2,335,473	2,287,221
Total Assets	$ 9,142,088	$ 8,791,396

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2012	2011
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable	$ -	$ 31,000
Notes Payable to Affiliated Companies	99,296	58,525
Long-Term Debt - Current Portion	125,000	62,000
Accounts Payable	262,857	340,321
Accounts Payable to Affiliated Companies	52,326	53,439
Obligations to Third Party Suppliers	67,344	67,967
Accrued Taxes	60,109	59,046
Regulatory Liabilities	32,119	108,291
Derivative Liabilities	96,931	95,881
Other Current Liabilities	125,662	102,065
Total Current Liabilities	921,644	978,535
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,336,105	1,215,989
Regulatory Liabilities	124,319	139,307
Derivative Liabilities	865,571	935,849
Accrued Pension, SERP and PBOP	304,696	260,571
Other Long-Term Liabilities	197,434	215,640
Total Deferred Credits and Other Liabilities	2,828,125	2,767,356
Capitalization:		
Long-Term Debt	2,737,790	2,521,753
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	1,640,149	1,613,503
Retained Earnings	839,628	735,948
Accumulated Other Comprehensive Loss	(1,800)	(2,251)
Common Stockholder's Equity	2,538,329	2,407,552
Total Capitalization	5,392,319	5,045,505

Commitments and Contingencies (Note 12)				
Total Liabilities and Capitalization	$	9,142,088	$	8,791,396

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2012	2011	2010
Operating Revenues	$ 2,407,449	$ 2,548,387	$ 2,999,102
Operating Expenses:			
Purchased Power and Transmission	858,231	982,514	1,292,733
Operations and Maintenance	635,733	580,736	494,203
Depreciation	166,853	157,747	172,167
Amortization of Regulatory Assets, Net	14,372	61,025	78,870
Amortization of Rate Reduction Bonds	-	-	167,021
Energy Efficiency Programs	89,299	90,297	92,279
Taxes Other Than Income Taxes	215,972	212,885	214,179
Total Operating Expenses	1,980,460	2,085,204	2,511,452
Operating Income	426,989	463,183	487,650
Interest Expense:			
Interest on Long-Term Debt	124,894	131,918	134,553
Interest on Rate Reduction Bonds	-	-	7,542
Other Interest	8,233	809	(4,357)
Interest Expense	133,127	132,727	137,738
Other Income, Net	10,300	9,741	26,669
Income Before Income Tax Expense	304,162	340,197	376,581
Income Tax Expense	94,437	90,033	132,438
Net Income	$ 209,725	$ 250,164	$ 244,143

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 209,725	$ 250,164	$ 244,143
Other Comprehensive Income, Net of Tax:			
Qualified Cash Flow Hedging Instruments	444	445	444

Changes in Unrealized Gains on Other Securities		7		17		14
Other Comprehensive Income, Net of Tax		451		462		458
Comprehensive Income	$	210,176	$	250,626	$	244,601

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

THE CONNECTICUT LIGHT AND POWER 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, 2010	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
Net Income				209,725		209,725
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(100,486)		(100,486)
Allocation of Benefits - ESOP			1,595			1,595
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			25,000			25,000
Other Comprehensive Income					451	451
Balance as of December 31, 2012	6,035,205	$ 60,352	$ 1,640,149	$ 839,628	$ (1,800)	$ 2,538,329

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2012	2011	2010
Operating Activities:			
Net Income	$ 209,725	$ 250,164	$ 244,143
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	2,080	3,215	7,484
Depreciation	166,853	157,747	172,167
Deferred Income Taxes	140,993	112,620	115,069
Pension, SERP and PBOP Expense, Net of PBOP Contributions	24,062	10,664	1,595
Regulatory (Under)/Over Recoveries, Net	(100,505)	(82,502)	37,528
Amortization of Regulatory Assets, Net	14,372	61,025	78,870
Amortization of Rate Reduction Bonds	-	-	167,021
Other	(31,032)	(36,928)	(55,515)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(7,741)	14,610	1,895
Materials and Supplies	(4,573)	(2,206)	3,377
Taxes Receivable/Accrued, Net	15,702	2,719	(56,002)
Accounts Payable	(190,240)	8,864	(35,976)
Other Current Assets and Liabilities, Net	(27,803)	13,291	15,649
Net Cash Flows Provided by Operating Activities	211,893	513,283	697,305
Investing Activities:			
Investments in Property, Plant and Equipment	(449,137)	(424,865)	(380,304)
Decrease in Notes Receivable to Affiliate	-	-	97,775
Proceeds from Sale of Assets	-	46,841	-
Other Investing Activities	32,009	16,001	5,385
Net Cash Flows Used in Investing Activities	(417,128)	(362,023)	(277,144)
Financing Activities:			

Cash Dividends on Common Stock	(100,486)	(243,218)	(217,691)
Cash Dividends on Preferred Stock	(5,559)	(5,559)	(5,559)
Increase in Short-Term Debt	58,000	31,000	-
Increase in Notes Payable to Affiliate	346,575	52,300	6,225
Issuance of Long-Term Debt	-	245,500	-
Retirements of Long-Term Debt	(116,400)	(245,500)	-
Capital Contributions from NU Parent	25,000	6,748	2,513
Retirements of Rate Reduction Bonds	-	-	(195,587)
Other Financing Activities	(1,895)	(2,292)	(345)
Net Cash Flows Provided by/(Used in) Financing Activities	205,235	(161,021)	(410,444)
Net (Decrease)/Increase in Cash	-	(9,761)	9,717
Cash - Beginning of Year	1	9,762	45
Cash - End of Year	$ 1	$ 1	$ 9,762

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

Company Report on Internal Controls Over Financial Reporting

NSTAR Electric Company

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of NSTAR Electric Company and subsidiaries (NSTAR Electric or the Company) and of other sections of this annual report. NSTAR Electric 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, NSTAR Electric 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, 2012.

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of NSTAR Electric Company:

We have audited the accompanying consolidated balance sheet of NSTAR Electric Company and subsidiaries (the "Company") as of December 31, 2012 and the related consolidated statements of income, comprehensive income, common stockholder s equity, and cash flows for the year then ended. Our audit also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audit. The consolidated financial statements and financial statement schedule of the Company for the years ended December 31, 2011 and 2010 were audited by other auditors whose report, dated February 7, 2012, expressed an unqualified opinion on those statements and included an explanatory paragraph relating to the merger agreement signed with Northeast Utilities.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such 2012 consolidated financial statements present fairly, in all material respects, the financial position of NSTAR Electric Company and subsidiaries as of December 31, 2012, and the results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 2012 financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Directors and Shareholder of NSTAR Electric Company:

In our opinion, the consolidated balance sheets, consolidated statements of income, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of NSTAR Electric Company and its subsidiaries at December 31, 2011 and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the two years in the period ended December 31, 2011 listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Boston, Massachusetts

February 7, 2012

NSTAR ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2012	2011
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 13,695	$ 9,373
Receivables, Net	202,025	232,828
Accounts Receivable from Affiliated Companies	160,176	389,652
Unbilled Revenues	41,377	40,380
Regulatory Assets	347,081	323,871
Prepayments and Other Current Assets	28,086	34,479
Total Current Assets	792,440	1,030,583
Property, Plant and Equipment, Net	4,735,297	4,447,258
Deferred Debits and Other Assets:		
Regulatory Assets	1,444,870	1,680,595
Other Long-Term Assets	87,382	81,890
Total Deferred Debits and Other Assets	1,532,252	1,762,485
Total Assets	$ 7,059,989	$ 7,240,326

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

NSTAR ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2012	2011
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable	$ 276,000	$ 141,500
Long-Term Debt - Current Portion	1,650	401,650
Accounts Payable	168,611	150,581
Accounts Payable to Affiliated Companies	247,061	514,377
Accumulated Deferred Income Taxes - Current Portion	104,668	101,819
Regulatory Liabilities	47,539	41,579
Other Current Liabilities	144,433	103,634
Total Current Liabilities	989,962	1,455,140
Rate Reduction Bonds	43,493	127,860
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,321,026	1,310,180
Regulatory Liabilities	244,224	239,858
Accrued Pension	360,932	357,685
Payable to Affiliated Companies	70,221	75,905
Other Long-Term Liabilities	183,190	195,606
Total Deferred Credits and Other Liabilities	2,179,593	2,179,234
Capitalization:		
Long-Term Debt	1,600,911	1,203,344
Preferred Stock Not Subject to Mandatory Redemption	43,000	43,000
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	992,625	992,625
Retained Earnings	1,210,405	1,239,123
Common Stockholder's Equity	2,203,030	2,231,748
Total Capitalization	3,846,941	3,478,092
Commitments and Contingencies (Note 12)		

Total Liabilities and Capitalization	$	7,059,989	$	7,240,326

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

NSTAR ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2012	2011	2010
Operating Revenues	$ 2,300,997	$ 2,403,053	$ 2,366,201
Operating Expenses:			
Purchased Power and Transmission	788,252	905,226	1,031,351
Operations and Maintenance	431,802	387,533	351,843
Depreciation	171,070	163,368	158,574
Amortization of Regulatory Assets, Net	117,682	82,979	19,071
Amortization of Rate Reduction Bonds	90,322	90,322	104,481
Energy Efficiency Programs	201,234	175,747	117,091
Taxes Other Than Income Taxes	119,219	111,705	104,978
Total Operating Expenses	1,919,581	1,916,880	1,887,389
Operating Income	381,416	486,173	478,812
Interest Expense:			
Interest on Long-Term Debt	87,100	90,040	90,630
Interest on Rate Reduction Bonds	3,585	7,226	11,235
Other Interest	(20,631)	(27,839)	(30,475)
Interest Expense	70,054	69,427	71,390
Other Income, Net	2,846	1,434	3,173
Income Before Income Tax Expense	314,208	418,180	410,595
Income Tax Expense	123,966	165,686	162,020
Net Income	$ 190,242	$ 252,494	$ 248,575

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

NSTAR ELECTRIC 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	Total Common Stockholder's Equity
Balance as of January 1, 2010	100	$ -	$ 992,625	$ 1,100,074	$ 2,092,699
Net Income				248,575	248,575
Dividends on Preferred Stock				(1,960)	(1,960)
Dividends on Common Stock				(188,200)	(188,200)
Balance as of December 31, 2010	100	-	992,625	1,158,489	2,151,114
Net Income				252,494	252,494
Dividends on Preferred Stock				(1,960)	(1,960)
Dividends on Common Stock				(169,900)	(169,900)
Balance as of December 31, 2011	100	-	992,625	1,239,123	2,231,748
Net Income				190,242	190,242
Dividends on Preferred Stock				(1,960)	(1,960)
Dividends on Common Stock				(217,000)	(217,000)
Balance as of December 31, 2012	100	$ -	$ 992,625	$ 1,210,405	$ 2,203,030

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

NSTAR ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2012	2011	2010
Operating Activities:			
Net Income	$ 190,242	$ 252,494	$ 248,575
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	40,301	22,582	29,417
Depreciation	171,070	163,368	158,574
Deferred Income Taxes	4,264	72,006	41,612
Pension, SERP and PBOP Expense	66,010	54,704	60,528
Pension Contributions	(25,000)	(125,000)	(25,000)
Regulatory (Under)/Over Recoveries, Net	(16,129)	68,353	95,532
Amortization of Regulatory Assets, Net	117,682	82,979	19,071
Amortization of Rate Reduction Bonds	90,322	90,322	104,481
Other	(32,048)	539	(76,866)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(10,496)	(26,041)	(37,132)
Materials and Supplies	1,813	(12,968)	3,077
Taxes Receivable/Accrued, Net	29,899	149,889	(20,270)
Accounts Payable	(59,217)	(53,939)	37,661
Other Current Assets and Liabilities, Net	22,568	7,040	(93,528)
Net Cash Flows Provided by Operating Activities	591,281	746,328	545,732
Investing Activities:			
Investments in Property, Plant and Equipment	(414,089)	(390,427)	(317,046)
Other Investing Activities	3,460	3,363	26,382
Net Cash Flows Used in Investing Activities	(410,629)	(387,064)	(290,664)
Financing Activities:			
Cash Dividends on Common Stock	(217,000)	(169,900)	(188,200)
Cash Dividends on Preferred Stock	(1,960)	(1,960)	(1,960)

Increase/(Decrease) in Short-Term Debt	134,500	(86,000)	(113,500)
Issuance of Long-Term Debt	400,000	-	300,000
Retirements of Long-Term Debt	(401,650)	(16,650)	(126,648)
Retirements of Rate Reduction Bonds	(84,367)	(84,346)	(119,014)
Other Financing Activities	(5,853)	-	(7,854)
Net Cash Flows Used in Financing Activities	(176,330)	(358,856)	(257,176)
Net Increase/(Decrease) in Cash and Cash Equivalents	4,322	408	(2,108)
Cash and Cash Equivalents - Beginning of Year	9,373	8,965	11,073
Cash and Cash Equivalents - End of Year	$ 13,695	$ 9,373	$ 8,965

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

Company Report on Internal Controls Over Financial Reporting

Public Service Company of New Hampshire

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, 2012.

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of Public Service Company of New Hampshire:

We have audited the accompanying consolidated balance sheets of Public Service Company of New Hampshire and subsidiaries (the "Company") as of December 31, 2012 and 2011 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, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Public Service Company of New Hampshire and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 27, 2013

This Page Intentionally Left Blank

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2012	2011
ASSETS		
Current Assets:		
Cash	$ 2,493	$ 56
Receivables, Net	87,164	87,545
Accounts Receivable from Affiliated Companies	723	1,294
Notes Receivable from Affiliated Companies	-	55,900
Unbilled Revenues	39,982	45,403
Taxes Receivable	17,177	7,424
Fuel, Materials and Supplies	95,345	124,744
Regulatory Assets	62,882	34,178
Prepayments and Other Current Assets	22,205	27,837
Total Current Assets	327,971	384,381
Property, Plant and Equipment, Net	2,352,515	2,256,688
Deferred Debits and Other Assets:		
Regulatory Assets	351,059	393,941
Other Long-Term Assets	83,052	81,531
Total Deferred Debits and Other Assets	434,111	475,472
Total Assets	$ 3,114,597	$ 3,116,541

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

100

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2012	2011
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ 63,300	$ -
Accounts Payable	62,864	106,377
Accounts Payable to Affiliated Companies	21,337	18,895
Accrued Interest	9,317	9,670
Regulatory Liabilities	23,002	24,500
Renewable Portfolio Standards Compliance Obligations	17,383	12,089
Other Current Liabilities	41,633	24,408
Total Current Liabilities	238,836	195,939
Rate Reduction Bonds	29,294	85,368
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	441,577	392,712
Regulatory Liabilities	52,418	54,415
Accrued Pension, SERP and PBOP	220,129	258,718
Other Long-Term Liabilities	47,896	53,304
Total Deferred Credits and Other Liabilities	762,020	759,149
Capitalization:		
Long-Term Debt	997,932	997,722
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	701,052	700,285
Retained Earnings	395,118	388,910
Accumulated Other Comprehensive Loss	(9,655)	(10,832)
Common Stockholder's Equity	1,086,515	1,078,363
Total Capitalization	2,084,447	2,076,085
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 3,114,597	$ 3,116,541

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)	2012	2011	2010
Operating Revenues	$ 988,013	$ 1,013,003	$ 1,033,439
Operating Expenses:			
Purchased Power, Fuel and Transmission	319,253	327,905	389,538
Operations and Maintenance	263,234	278,153	274,165
Depreciation	87,602	76,167	67,237
Amortization of Regulatory Assets/(Liabilities), Net	(24,086)	25,383	11,232
Amortization of Rate Reduction Bonds	56,645	53,389	50,357
Energy Efficiency Programs	14,245	12,917	12,038
Taxes Other Than Income Taxes	66,025	58,985	52,686
Total Operating Expenses	782,918	832,899	857,253
Operating Income	205,095	180,104	176,186
Interest Expense:			
Interest on Long-Term Debt	46,228	36,832	36,220
Interest on Rate Reduction Bonds	2,687	6,276	9,660
Other Interest	1,313	1,039	1,187
Interest Expense	50,228	44,147	47,067
Other Income, Net	3,008	14,255	11,749
Income Before Income Tax Expense	157,875	150,212	140,868
Income Tax Expense	60,993	49,945	50,801
Net Income	$ 96,882	$ 100,267	$ 90,067

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 96,882	$ 100,267	$ 90,067
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	1,162	(10,260)	87

Changes in Unrealized Gains on Other Securities		13		29		24
Changes in Funded Status of Pension, SERP and PBOP						
Benefit Plans		2		-		-
Other Comprehensive Income/(Loss), Net of Tax		1,177		(10,231)		111
Comprehensive Income	$	98,059	$	90,036	$	90,178

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, 2010	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
Net Income				96,882		96,882
Dividends on Common Stock				(90,674)		(90,674)
Allocation of Benefits - ESOP			767			767
Other Comprehensive Income					1,177	1,177
Balance as of December 31, 2012	301	$ -	$ 701,052	$ 395,118	$ (9,655)	$ 1,086,515

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

(Thousands of Dollars)	For the Years Ended December 31, 2012	2011	2010
Operating Activities:			
Net Income	$ 96,882	$ 100,267	$ 90,067
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	6,457	7,035	8,858
Depreciation	87,602	76,167	67,237
Deferred Income Taxes	58,552	75,628	39,225
Pension, SERP and PBOP Expense	26,312	27,298	29,112
Pension and PBOP Contributions	(96,880)	(121,178)	(53,689)
Regulatory (Under)/Over Recoveries, Net	(183)	6,079	(2,834)
Amortization of Regulatory Assets/(Liabilities), Net	(24,086)	25,383	11,232
Amortization of Rate Reduction Bonds	56,645	53,389	50,357
Settlements of Cash Flow Hedge Instruments	-	(18,072)	-
Other	4,748	(20,958)	(31,590)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(84)	7,833	(24,497)
Fuel, Materials and Supplies	25,897	(9,873)	14,891
Taxes Receivable/Accrued, Net	(9,752)	5,139	10,037
Accounts Payable	(15,248)	(4,517)	(14,427)
Other Current Assets and Liabilities, Net	13,436	(4,915)	1,294
Net Cash Flows Provided by Operating Activities	230,298	204,705	195,273
Investing Activities:			
Investments in Property, Plant and Equipment	(203,902)	(241,772)	(296,335)
Decrease/(Increase) in Notes Receivable from Affiliate	55,900	(55,900)	-
Other Investing Activities	4,065	2,089	(7,819)
Net Cash Flows Used in Investing Activities	(143,937)	(295,583)	(304,154)

Financing Activities:						
Cash Dividends on Common Stock		(90,674)		(58,828)		(50,584)
(Decrease)/Increase in Short-Term Debt		-		(30,000)		30,000
Issuance of Long-Term Debt		-		282,000		-
Retirements of Long-Term Debt		-		(119,800)		-
Increase/(Decrease) in Notes Payable to Affiliate		63,300		(47,900)		21,200
Capital Contributions from NU Parent		-		120,030		158,969
Retirements of Rate Reduction Bonds		(56,074)		(52,879)		(49,867)
Other Financing Activities		(476)		(4,248)		(252)
Net Cash Flows (Used in)/Provided by Financing Activities		(83,924)		88,375		109,466
Net Increase/(Decrease) in Cash		2,437		(2,503)		585
Cash - Beginning of Year		56		2,559		1,974
Cash - End of Year	$	2,493	$	56	$	2,559

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

Company Report on Internal Controls Over Financial Reporting

Western Massachusetts Electric Company

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 of December 31, 2012.

February 27, 2013

105

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of Western Massachusetts Electric Company:

We have audited the accompanying consolidated balance sheets of Western Massachusetts Electric Company and subsidiary (the "Company") as of December 31, 2012 and 2011 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, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Western Massachusetts Electric Company and subsidiary as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 27, 2013

This Page Intentionally Left Blank

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2012	2011
ASSETS		
Current Assets:		
Cash	$ 1	$ 1
Receivables, Net	47,297	42,757
Accounts Receivable from Affiliated Companies	164	633
Notes Receivable from Affiliated Companies	-	11,000
Unbilled Revenues	16,192	16,277
Taxes Receivable	15,513	2,263
Regulatory Assets	42,370	35,520
Marketable Securities	27,352	26,335
Prepayments and Other Current Assets	7,963	6,456
Total Current Assets	156,852	141,242
Property, Plant and Equipment, Net	1,290,498	1,077,833
Deferred Debits and Other Assets:		
Regulatory Assets	221,752	233,247
Marketable Securities	30,342	30,794
Other Long-Term Assets	23,625	19,777
Total Deferred Debits and Other Assets	275,719	283,818
Total Assets	$ 1,723,069	$ 1,502,893

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2012	2011
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ 31,900	$ -
Long-Term Debt - Current Portion	55,000	-
Accounts Payable	68,141	111,566
Accounts Payable to Affiliated Companies	7,103	10,626
Accrued Interest	8,304	7,714
Regulatory Liabilities	21,037	33,056
Other Current Liabilities	24,909	13,041
Total Current Liabilities	216,394	176,003
Rate Reduction Bonds	9,352	26,892
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	303,111	244,511
Regulatory Liabilities	9,686	16,597
Accrued Pension, SERP and PBOP	36,099	29,546
Other Long-Term Liabilities	40,148	47,498
Total Deferred Credits and Other Liabilities	389,044	338,152
Capitalization:		
Long-Term Debt	550,270	499,545
Common Stockholder's Equity:		
Common Stock	10,866	10,866
Capital Surplus, Paid In	390,412	340,115
Retained Earnings	160,577	115,506
Accumulated Other Comprehensive Loss	(3,846)	(4,186)
Common Stockholder's Equity	558,009	462,301
Total Capitalization	1,108,279	961,846
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 1,723,069	$ 1,502,893

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2012	2011	2010
Operating Revenues	$ 441,164	$ 417,315	$ 395,161
Operating Expenses:			
Purchased Power and Transmission	136,086	161,480	175,604
Operations and Maintenance	97,031	80,241	87,088
Depreciation	29,971	26,455	23,561
Amortization of Regulatory Assets, Net	410	4,492	1,892
Amortization of Rate Reduction Bonds	17,632	16,523	15,494
Energy Efficiency Programs	27,802	21,804	16,336
Taxes Other Than Income Taxes	21,458	17,957	16,529
Total Operating Expenses	330,390	328,952	336,504
Operating Income	110,774	88,363	58,657
Interest Expense:			
Interest on Long-Term Debt	23,462	20,023	17,988
Interest on Rate Reduction Bonds	1,229	2,335	3,372
Other Interest	1,943	1,254	479
Interest Expense	26,634	23,612	21,839
Other Income, Net	2,503	1,489	2,597
Income Before Income Tax Expense	86,643	66,240	39,415
Income Tax Expense	32,140	23,186	16,325
Net Income	$ 54,503	$ 43,054	$ 23,090

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 54,503	$ 43,054	$ 23,090
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	338	(4,108)	(79)

Changes in Unrealized Gains on Other Securities		2		5		4
Other Comprehensive Income/(Loss), Net of Tax		340		(4,103)		(75)
Comprehensive Income	$	54,843	$	38,951	$	23,015

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, 2010	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
Net Income				54,503		54,503
Dividends on Common Stock				(9,432)		(9,432)
Allocation of Benefits - ESOP			297			297
Capital Contributions from NU Parent			50,000			50,000
Other Comprehensive Income					340	340
Balance as of December 31, 2012	434,653	$ 10,866	$ 390,412	$ 160,577	$ (3,846)	$ 558,009

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2012	2011	2010
Operating Activities:			
Net Income	$ 54,503	$ 43,054	$ 23,090
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	2,294	3,133	9,747
Depreciation	29,971	26,455	23,561
Deferred Income Taxes	53,942	23,056	10,963
Regulatory (Under)/Over Recoveries, Net	(19,152)	3,328	(11,048)
Amortization of Regulatory Assets, Net	410	4,492	1,892
Amortization of Rate Reduction Bonds	17,632	16,523	15,494
Settlement of Cash Flow Hedge Instrument	-	(6,859)	-
Other	(6,248)	(3,719)	(7,567)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(8,896)	(7,263)	(6,838)
Materials and Supplies	(2,882)	331	4,650
Taxes Receivable/Accrued, Net	(8,311)	5,084	(393)
Accounts Payable	(19,297)	12,956	(92)
Other Current Assets and Liabilities, Net	581	3,824	2,406
Net Cash Flows Provided by Operating Activities	94,547	124,395	65,865
Investing Activities:			
Investments in Property, Plant and Equipment	(264,175)	(237,996)	(115,178)
Proceeds from Sales of Marketable Securities	79,769	125,157	114,191
Purchases of Marketable Securities	(80,529)	(125,453)	(114,587)
Decrease/(Increase) in Notes Receivable from Affiliate	11,000	(11,000)	-
Other Investing Activities	(28)	(1,919)	(888)
Net Cash Flows Used in Investing Activities	(253,963)	(251,211)	(116,462)

Financing Activities:			
Cash Dividends on Common Stock	(9,432)	(26,305)	(14,882)
Issuance of Long-Term Debt	150,000	100,000	95,000
Retirements of Long-Term Debt	(53,800)	-	-
Increase/(Decrease) in Notes Payable to Affiliate	31,900	(20,400)	(115,700)
Retirements of Rate Reduction Bonds	(17,540)	(16,433)	(15,410)
Capital Contributions from NU Parent	50,000	91,812	102,479
Other Financing Activities	8,288	(1,858)	(890)
Net Cash Flows Provided by Financing Activities	159,416	126,816	50,597
Net Change in Cash	-	-	-
Cash - Beginning of Year	1	1	1
Cash - End of Year	$ 1	$ 1	$ 1

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

NORTHEAST UTILITIES AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARY

NSTAR ELECTRIC COMPANY AND SUBSIDIARIES

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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.

About NU, CL&P, NSTAR Electric, PSNH and WMECO

NU Consolidated: NU is a public utility holding company primarily engaged through its wholly owned regulated utility subsidiaries in the energy delivery business. NU's wholly owned regulated utility subsidiaries included CL&P, PSNH, WMECO and Yankee Gas prior to NU's merger with NSTAR. On April 10, 2012, NU acquired 100 percent of the outstanding common shares of NSTAR, at which time NSTAR (through a successor, NSTAR LLC) became a direct wholly owned subsidiary of NU along with its regulated utility subsidiaries, NSTAR Electric and NSTAR Gas. NU provides energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated utilities in Connecticut, Massachusetts and New Hampshire. See Note 2, "Merger of NU and NSTAR," for further information regarding the merger.

NU, CL&P, NSTAR Electric, 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 regulation of rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the PURA for CL&P and Yankee Gas, the DPU for NSTAR Electric, NSTAR Gas and WMECO, and the NHPUC as well as certain regulatory oversight by the Vermont Public Service Board and the Maine Public Utilities Commission for PSNH).

Regulated Companies: CL&P, NSTAR Electric, PSNH and WMECO furnish franchised retail electric service in Connecticut, Massachusetts and New Hampshire. NSTAR Gas is engaged in the distribution and sale of natural gas to customers within central and eastern Massachusetts. Yankee Gas owns and operates Connecticut's largest natural gas distribution system. CL&P, NSTAR Electric, PSNH and WMECO's results include the operations of their respective distribution and transmission businesses. PSNH and WMECO's distribution results include the operations of their respective generation businesses. NU also has a regulated subsidiary, NPT, which 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, 2012, NU Enterprises primary business consisted of Select Energy s remaining energy wholesale marketing contracts with a municipal authority that expires on December 31, 2013 and related purchase contracts and NGS operation and maintenance agreements as well as its subsidiary, E.S. Boulos Company, an electrical contractor based in Maine that NU Enterprises continues to own and manage. NUSCO, NSTAR Electric & Gas, RRR, Renewable Properties, Inc. and Properties, Inc. provide support services to NU, including its regulated companies. Harbor Electric Energy Company, a wholly-owned subsidiary of NSTAR Electric, provides distribution service and ongoing support to its only customer, the Massachusetts Water Resources Authority. NSTAR also has unregulated subsidiaries in telecommunications (NSTAR Communications, Inc.) and natural gas liquefaction and storage services (Hopkinton).

B.

Basis of Presentation

The consolidated financial statements of NU, CL&P, NSTAR Electric, PSNH and WMECO include the accounts of each of 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.

NSTAR Electric continues to maintain reporting requirements as an SEC registrant. The information disclosed for NSTAR Electric represents its results of operations for each of the years ended December 31, 2012, 2011 and 2010 and the financial position as of December 31, 2012 and 2011, presented on a comparable basis. NU did not apply "push-down accounting" to NSTAR Electric, whereby the adjustments of assets and liabilities to fair value and the resultant goodwill would be shown on the financial statements of the acquired subsidiary. NU's consolidated financial information includes NSTAR LLC and its subsidiaries' results of operations from April 10, 2012 through December 31, 2012.

On April 10, 2012, upon consummation of the merger with NSTAR, NSTAR Electric's ownership in CYAPC and YAEC combined with CL&P's, PSNH's and WMECO's respective ownership interests in CYAPC and YAEC totaled greater than 50 percent, requiring NU to consolidate CYAPC and YAEC from April 10, 2012 and forward. The investment in CYAPC and YAEC had previously been accounted for under the equity method by NU. The consolidation of CYAPC and YAEC results in NU recording nuclear decommissioning trust marketable securities of $340.4 million, regulatory assets of $214 million, long-term debt associated with the long-term spent nuclear fuel disposal liabilities of $179.3 million, net accumulated deferred income tax liability of $56.4 million and asset retirement obligations related to decommissioning activity of $311.4 million as of December 31, 2012. At the NU consolidated level, intercompany transactions between CL&P, NSTAR Electric, PSNH and WMECO and the CYAPC and YAEC companies have been eliminated in consolidation. For CL&P, NSTAR Electric, PSNH and WMECO, the investment in CYAPC and YAEC continue to be accounted for under the equity method. See Note 1J, "Summary of Significant Accounting Policies Equity Method Investments," for further information.

NPT, a limited liability company, was formed 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. On April 10, 2012, upon consummation of the merger with NSTAR, an NSTAR subsidiary that owned 25 percent of NPT was merged into NUTV, resulting in NUTV owning 100 percent of NPT. Accordingly, 100 percent ownership of NPT was reflected in Common Shareholders' Equity as of December 31, 2012 on the accompanying consolidated balance sheet. See Note 2, "Merger of NU and NSTAR," and Note 19, "Common Shareholders' Equity and Noncontrolling Interests," for further information.

NU's utility subsidiaries are subject to the application of accounting guidance for entities with rate-regulated operations that considers the effect of regulation resulting from differences in the timing of the recognition of certain revenues and expenses from those of other businesses and industries. NU's utility subsidiaries' energy delivery business is subject to rate-regulation that is based on cost recovery and meets the criteria for application of rate-regulated accounting. See Note 3, "Regulatory Accounting," for further information.

Certain prior year amounts in NSTAR Electric's accompanying consolidated balance sheet, statements of income and cash flows have been reclassified between line items for comparative purposes and in order to conform to NU's presentation. The reclassifications did not affect NSTAR Electric's net income. The NSTAR Electric consolidated statements of cash flows were revised to correct an error in the presentation of cash deposits related to the RRBs. The impact of this revision was an increase in investing cash inflows from Other Investing Activities in an amount of $1.7 million and $24.1 million and a corresponding increase to financing cash outflows from Retirements of Rate Reduction Bonds for the years ended December 31, 2011 and 2010, respectively. These revisions had no impact on NSTAR Electric s results of operations or cash balance and are not deemed material, individually or in the aggregate, to the previously issued consolidated financial statements.

Certain changes in classification and corresponding reclassifications of prior year data were made in the accompanying consolidated balance sheets and statements of income for NU, CL&P, PSNH and WMECO and statements of cash flows for NU, CL&P and WMECO for comparative purposes to conform the current year presentation. The consolidated statements of income reflect the reclassification of transmission expenses from Other Operating Expenses, as originally reported, to Purchased Power, Fuel and Transmission and the reclassification of energy efficiency expenses primarily from Other Operating Expenses, as originally reported, to Energy Efficiency Programs. In addition, Other Operating Expenses and Maintenance, as originally reported, were combined and are reported in aggregate as Operations and Maintenance. The reclassifications on the statements of income were as follows:

	Transmission Expense For the Years Ended December 31,		**Energy Efficiency Expense For the Years Ended December 31,**	
(Millions of Dollars)	**2011**	**2010**	**2011**	**2010**
NU	$ 77.2	$ 48.9	$ 131.4	$ 124.0
CL&P	52.6	39.4	90.3	92.3
PSNH	19.1	26.4	12.9	12.0
WMECO	15.9	18.3	21.8	16.3

Effective January 1, 2012, NSTAR Electric changed its estimates with respect to the allowance for doubtful accounts, incurred but not reported claims on medical benefits, general and workers' compensation liabilities and compensation accruals. The total aggregate impact of these changes in estimates on NSTAR Electric's accompanying consolidated statements was a decrease to net income of $11.4 million, after-tax, for the year ended December 31, 2012.

In accordance with accounting guidance on noncontrolling interests in consolidated financial statements, the Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric, which are not owned by NU or its consolidated subsidiaries and are not subject to mandatory redemption, have been presented as noncontrolling interests in the accompanying consolidated financial statements of NU. The Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric are considered to be temporary equity and have been classified between liabilities and permanent shareholders' equity on the accompanying consolidated balance sheets of NU, CL&P and NSTAR Electric due to a provision in the preferred stock agreements of both CL&P and NSTAR Electric that grant preferred stockholders the right to elect a majority of the CL&P and NSTAR Electric Board of Directors, respectively, should certain conditions exist, such as if preferred dividends are in arrears for a specified amount of time. 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 Electric.

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

114

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. See Note 23, "Subsequent Events," for further information.

C.

Recently Adopted Accounting Standards

In the first quarter of 2012, NU adopted the Financial Accounting Standards Board s (FASB) final Accounting Standards Update (ASU) on fair value measurement. The ASU did not have an impact on NU s financial position, results of operations or cash flows, but required additional financial statement disclosures related to fair value measurements. For further information, see Note 5, "Derivative Instruments," to the consolidated financial statements.

In the first quarter of 2012, NU adopted the FASB s final ASU on testing goodwill for impairment. The ASU provides the election 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 ASU 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. NU did not utilize the election provided by this ASU in its current year evaluation of goodwill.

In the first quarter of 2012, NU adopted the FASB s final ASU on the presentation of comprehensive income. The ASU does not change existing guidance on which items should be presented in other comprehensive income but requires other comprehensive income to be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income. The ASU did not affect the calculation of net income, comprehensive income or EPS. The ASU did not have an impact on NU s financial position, results of operations or cash flows.

D.

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.

E.

Provision for Uncollectible Accounts

NU, including CL&P, NSTAR Electric, PSNH and WMECO, presents its receivables at net realizable value by maintaining a provision for uncollectible accounts receivables. 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 assesses the collectibility of 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 PURA allows CL&P and Yankee Gas to accelerate the recovery of accounts receivable balances attributable to qualified customers under financial or medical duress (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 basic service and certain uncollectible hardship accounts receivable in rates. As of December 31, 2012, CL&P, WMECO and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $65.2 million, $4.7 million and $6.4 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, 2011, these amounts totaled $68.6 million, $5.4 million and $6.8 million, respectively. These amounts are reflected in the total provision for uncollectible accounts in the table below.

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

	As of December 31,			
(Millions of Dollars)	**2012**		**2011**	
NU [2]	$	165.5	$	115.7
CL&P [2]		77.6		83.5
NSTAR Electric [1]		44.1		27.1
PSNH		6.8		7.2
WMECO [2]		8.5		10.0

(1)

NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011.

(2)

NU, CL&P and WMECO balances as of December 31, 2011 have been reclassified to include the uncollectible hardship reserve in the total provision for uncollectible accounts.

F.

Fuel, Materials and Supplies and Allowance Inventory

Fuel, Materials and Supplies include natural gas, coal, biomass, oil and materials purchased primarily for construction or operation and maintenance purposes. Natural gas inventory, coal, biomass, 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, 2012 and 2011, PSNH had $0.4 million and $0.8 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 $19.4 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 $0.4 million, $5.1 million and $6.6 million for the years ended December 31, 2012, 2011, and 2010, respectively, which were included in Purchased Power, Fuel and Transmission on the accompanying consolidated statements of income. These costs are recovered from customers through energy supply revenues.

G.

Restricted Cash and Other Deposits

As of December 31, 2012, NU, CL&P and PSNH had $3.3 million, $1.3 million and $1.7 million, respectively, of restricted cash, primarily relating to amounts held in escrow, insurance proceeds on bondable property at PSNH and amounts related to the sale of land, which were included in Prepayments and Other Current Assets on the accompanying consolidated balance sheets. As of December 31, 2011, these amounts were $17.9 million, $9.4 million and $7 million for NU, CL&P and PSNH, respectively.

As of December 31, 2012, NU had $14.6 million of cash collateral posted not subject to master netting agreements, primarily with ISO-NE. As of December 31, 2011, there was no cash posted with ISO-NE and $10.9 million posted with other counterparties.

As of December 31, 2012, NU, NSTAR Electric, PSNH and WMECO had $69.4 million, $42.2 million, $22 million and $5.1 million, respectively, on deposit related to subsidiaries used to facilitate the issuance of RRBs. As of December 31, 2011, these amounts were $29.5 million, $40.9 million, $24.4 million and $5.1 million, respectively. These amounts are included in Prepayments and Other Current Assets and Other Long-Term Assets on the accompanying consolidated balance sheets. As of December 31, 2011, the NSTAR Electric amount was not included in NU consolidated.

H.

Fair Value Measurements

NU, including CL&P, NSTAR Electric, PSNH, and WMECO, applies fair value measurement guidance to derivative contracts recorded at fair value and to the marketable securities held in the NU supplemental benefit trust, WMECO's spent nuclear fuel trust and CYAPC's and YAEC's nuclear decommissioning trusts. Fair value measurement guidance is also applied to investment valuations used to calculate the funded status of NU's Pension and PBOP Plans, including NSTAR Electric's Pension Plan, and nonrecurring fair value measurements of nonfinancial assets such as goodwill and AROs.

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 2, "Merger of NU and NSTAR," Note 5, "Derivative Instruments," Note 6, "Marketable Securities," Note 7, "Asset Retirement Obligations," and Note 14, "Fair Value of Financial Instruments," to the consolidated financial statements.

I.

Derivative Accounting

Many of CL&P's, NSTAR Electric's, PSNH's and WMECO s contracts for the purchase and sale of energy or energy-related products are derivatives, along with NU Enterprises' remaining wholesale marketing contracts and NSTAR Gas' NYMEX futures. 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 can have a significant impact on the consolidated financial statements. Any change in the fair value of derivatives related to the Regulated companies is offset by a regulatory asset or liability, as this change will be recovered from or refunded to customers in future rates.

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 fair value of derivative assets and liabilities with the same counterparty are offset and recorded as a net derivative asset or liability on 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 Purchased Power, Fuel and Transmission on the accompanying consolidated statements of income.

For further information regarding derivative contracts of NU, CL&P, NSTAR Electric and WMECO and their accounting, see Note 5, "Derivative Instruments," to the consolidated financial statements.

J.

Equity Method Investments

Regional Decommissioned Nuclear Companies: CL&P, NSTAR Electric, PSNH and WMECO own common stock in three regional nuclear generation companies (CYAPC, YAEC and MYAPC, collectively referred to as the Yankee Companies), each of which owned a single nuclear generating facility that has been decommissioned. On April 10, 2012, upon consummation of the merger with NSTAR, NSTAR Electric's ownership in CYAPC and YAEC combined with CL&P's, PSNH's and WMECO's respective ownership interests in CYAPC and YAEC totaled greater than 50 percent, requiring NU to consolidate CYAPC and YAEC from April 10, 2012 and forward. The investment in CYAPC and YAEC had previously been accounted for under the equity method of accounting by NU. For CL&P, NSTAR Electric, PSNH and WMECO, the investment in CYAPC and YAEC continues to be accounted for under the equity method. At the NU consolidated level, intercompany transactions between CL&P, NSTAR Electric, PSNH and WMECO and the CYAPC and YAEC companies have been eliminated in consolidation.

Ownership interests in the Yankee Companies as of December 31, 2012 and 2011 were as follows:

(Percent)	**CYAPC**	**YAEC**	**MYAPC**
CL&P	34.5	24.5	12.0
NSTAR Electric	14.0	14.0	4.0
PSNH	5.0	7.0	5.0
WMECO	9.5	7.0	3.0

The total carrying values of CL&P's, NSTAR Electric's, PSNH's and WMECO's ownership interests in CYAPC, YAEC and MYAPC, which are included in Other Long-Term Assets on their respective accompanying consolidated balance sheets are as follows:

	As of December 31,	
(Millions of Dollars)	**2012**	**2011** [(1)]
CL&P	$ 1.4	$ 1.4
NSTAR Electric	0.6	0.6
PSNH	0.3	0.3
WMECO	0.4	0.4

(1)

The NSTAR Electric carrying value was not included in NU consolidated as of December 31, 2011.

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

Other Investments: As of December 31, 2012, NU had a 37.2 percent (14.5 percent of which related to NSTAR Electric) equity ownership interest in two companies that transmit electricity imported from the Hydro-Québec system in Canada. Prior to the merger with NSTAR on April 10, 2012, NU had a 22.7 percent equity ownership interest in these companies. These investments are accounted for under the equity method of accounting. NU s investment totaled $6 million and $4.6 million as of December 31, 2012 and 2011, respectively, and NSTAR Electric's investment totaled $2.3 million and $3 million as of December 31, 2012 and 2011, respectively. The NSTAR Electric investment was not included in NU consolidated as of December 31, 2011. As of December 31, 2012 and 2011, NU also had an equity ownership interest of $6.8 million and $4.2 million in an energy investment fund, respectively.

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.

K.

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' rates are designed to recover their incurred costs, plus an allowed rate of return on certain unrecovered costs. The Regulated companies also utilize regulatory commission-approved tracking mechanisms to recover certain costs on a fully-reconciling basis. These tracking mechanisms require 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 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 Purchased Power, Fuel, and Transmission, and sales of energy associated with these purchases are recorded in Operating Revenues.

Regulated Companies' Unbilled Revenues: Because customers are billed throughout the month based on pre-determined cycles rather than on a calendar month basis, an estimate of electricity or natural gas delivered to customers for which the customers have not yet been billed is calculated as of the balance sheet date. Unbilled revenues are included in Operating Revenues on the consolidated statements of income and are assets on the consolidated balance sheets. Actual amounts billed to customers when meter readings become available may vary from the estimated amount.

The Regulated companies estimate unbilled sales 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 unbilled sales to the respective customer classes, then applying an estimated rate by customer class to those 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, NSTAR Electric, PSNH, and WMECO are collected under the ISO New England Inc. Transmission, Markets and Services Tariff (ISO-NE Tariff). The ISO-NE Tariff includes Regional Network Service (RNS) and Schedule 21 - NU rate schedules to recover fees for transmission and other services for CL&P, PSNH and WMECO and the Schedule 21 - NSTAR rate schedules recover fees and other services for NSTAR Electric. The RNS rate, administered by ISO-NE and billed to all New England transmission users, including CL&P, NSTAR Electric, 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 and Schedule 21 - NSTAR rates, administered by NU, recover the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate. The Schedule 21 - NU rate is reset on January 1st and June 1st of each year, while the Schedule 21 - NSTAR rate is reset on June 1st of each year. The Schedule 21 - NU and Schedule 21 - NSTAR rate calculations recover 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, NSTAR Electric s, PSNH's and WMECO's regional and local revenue requirements as prescribed in the ISO-NE Tariff. The RNS and Schedule 21 - NU and Schedule 21 - NSTAR 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.

Regulated Companies' Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution businesses of CL&P, NSTAR Electric, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. CL&P, NSTAR Electric, 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.

L.

Operating Expenses

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

	For the Years Ended December 31,		
(Millions of Dollars)	**2012** [(1)]	**2011**	**2010**
NU	$ 346.8	$ 307.9	$ 391.6
PSNH	103.4	115.9	184.3
Yankee Gas	145.9	191.3	206.4
NSTAR Gas	97.2	N/A	N/A

(1) Includes the NSTAR Gas costs from the date of the merger, April 10, 2012, through December 31, 2012.

M.

Allowance for Funds Used During Construction

AFUDC represents the cost of borrowed and equity funds used to finance construction and is included in the cost of the Regulated companies' utility plant. 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. AFUDC costs are recovered from customers over the service life of the related plant in the form of increased revenue collected as a result of higher depreciation expense.

NU	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	**2012**	**2011**	**2010**
AFUDC:			
Borrowed Funds	$ 5.3	$ 11.8	$ 10.2
Equity Funds	6.8	22.5	16.7
Total	$ 12.1	$ 34.3	$ 26.9
Average AFUDC Rate	3.7%	7.3%	7.1%

	For the Years Ended December 31,											
	2012				**2011**				**2010**			
(Millions of Dollars,		**NSTAR**				**NSTAR**				**NSTAR**		
	CL&P	**Electric** [(1)]	**PSNH**	**WMECO**	**CL&P**	**Electric** [(1)]	**PSNH**	**WMECO**	**CL&P**	**Electric** [(1)]	**PSNH**	**WMECO**

except percentages)												
AFUDC:												
Borrowed Funds	$ 2.5	$ 0.3	$ 1.6	$ 0.5	$ 3.3	$ 0.2	$ 7.1	$ 0.5	$ 2.7	$ 0.1	$ 6.6	$ 0.3
Equity Funds	1.9	-	1.9	1.0	6.0	-	13.2	1.0	4.9	-	10.4	0.6
Total	$ 4.4	$ 0.3	$ 3.5	$ 1.5	$ 9.3	$ 0.2	$ 20.3	$ 1.5	$ 7.6	$ 0.1	$ 17.0	$ 0.9
Average AFUDC Rate	3.6%	0.4%	5.9%	6.8%	8.3%	0.3%	7.1%	7.4%	8.3%	0.3%	6.8%	6.4%

(1)

NSTAR Electric amounts are included in NU consolidated from the date of the merger, April 10, 2012, through December 31, 2012. NSTAR Electric amounts are not included in NU consolidated for the years ended December 31, 2011 and 2010.

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.

N.

Other Income, Net

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. For CL&P, NSTAR Electric, PSNH and WMECO, equity in earnings relate to investments in CYAPC, YAEC and MYAPC and also NSTAR Electric's investment in two regional transmission companies, which are all accounted for on the equity method. On an NU consolidated basis, equity in earnings relate to the investment in MYAPC and NU's investment in two regional transmission companies.

O.

Other Taxes

Gross receipts taxes levied by the state of Connecticut are collected by CL&P and Yankee Gas from their respective customers. These gross receipts taxes are shown on a gross basis with collections in Operating Revenues and payments in Taxes Other Than Income Taxes on the accompanying consolidated statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2012**	**2011**	**2010**
NU	$ 135.0	$ 137.8	$ 143.7
CL&P	120.7	121.6	128.0

Certain sales taxes are also collected by CL&P, NSTAR Electric, WMECO, Yankee Gas and NSTAR 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.

P. **Supplemental Cash Flow Information**

NU	As of and For the Years Ended December 31,		
(Millions of Dollars)	**2012**	**2011**	**2010**
Cash Paid/(Received) During the Year for:			
Interest, Net of Amounts Capitalized	$ 356.5	$ 256.3	$ 258.3
Income Taxes	(12.8)	(76.6)	84.5
Non-Cash Investing Activities:			
Plant Additions Included in Accounts Payable (As of)	160.6	168.5	127.9

	As of and For the Years Ended December 31,											
	2012				**2011**				**2010**			
(Millions of Dollars)	**CL&P**	**NSTAR Electric (1)**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric (1)**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric (1)**	**PSNH**	**WMECO**
Cash Paid/(Received) During the Year for:												
Interest, Net of Amounts Capitalized	$ 129.4	$ 94.6	$ 49.8	$ 25.8	$ 136.6	$ 96.1	$ 49.3	$ 22.1	$ 142.2	$ 95.8	$ 51.4	$ 20.2
Income Taxes	(42.0)	88.1	14.7	(8.4)	(27.5)	(62.2)	(29.0)	(4.9)	71.5	147.6	1.6	5.0
Non-Cash Investing Activities:												
Plant Additions Included in Accounts Payable (As of)	42.8	50.0	16.8	30.0	32.7	34.3	51.1	61.3	46.2	16.7	35.8	21.2

(1)

NSTAR Electric amounts are included in NU consolidated from the date of the merger, April 10, 2012, through December 31, 2012. NSTAR Electric amounts are not included in NU consolidated for the years ended December 31, 2011 and 2010.

The merger of NU with NSTAR on April 10, 2012 represented a significant non-cash transaction. Refer to Note 2, "Merger of NU and NSTAR," for further information on the purchase price of NSTAR.

Q.

Related Parties

NUSCO and NSTAR Electric & Gas, NU's service companies, provide 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, 2012 and 2011, CL&P, PSNH and WMECO had long-term receivables from NUSCO in the amounts of $25 million, $3.8 million and $5.5 million, respectively, which were included in Other Long-Term Assets on the accompanying consolidated balance sheets. These amounts related to the funding of investments held in trust by NUSCO in connection with certain postretirement benefits for CL&P, PSNH and WMECO employees and have been eliminated in consolidation on the NU financial statements.

NSTAR Electric s consolidated balance sheets included $70.2 million and $75.9 million in Payable to Affiliated Companies as of December 31, 2012 and 2011, respectively. These amounts related to payments received from affiliates as a result of NSTAR Electric s role as the sponsor of the NSTAR Pension Plan.

Included in the CL&P, NSTAR Electric, PSNH and WMECO consolidated balance sheets as of December 31, 2012 and 2011 were Accounts Receivable from Affiliated Companies and Accounts Payable to Affiliated Companies relating to transactions between CL&P, NSTAR Electric, 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 NSTAR Foundation is an independent not-for-profit entity designed to support local charitable organizations in NSTAR s service territory that improve the quality of life for its customers. The Board of Directors of both the NU Foundation and NSTAR Foundation consist of certain NU officers. The NU Foundation and the NSTAR Foundation are not included in the consolidated financial statements of NU as they are not-for-profit entities and the Company does not have title to the Foundations' assets and cannot receive contributions back from the Foundations.

120

2.

MERGER OF NU AND NSTAR

On April 10, 2012, NU acquired 100 percent of the outstanding common shares of NSTAR. Pursuant to the terms and conditions of the Agreement and Plan of Merger, as amended, the "Merger Agreement," NSTAR merged into NSTAR LLC, becoming a wholly-owned subsidiary of NU.

NSTAR LLC is a holding company engaged through its subsidiaries in the energy delivery business serving electric and natural gas distribution customers in Massachusetts. The merger was structured as a merger of equals in a tax-free exchange of shares. As part of the merger, NSTAR shareholders received 1.312 NU common shares for each NSTAR common share owned (the "exchange ratio") as of the acquisition date. 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 of the merger in October 2010. NU issued approximately 136 million common shares to the NSTAR shareholders as a result of the merger, which brought the total common shares outstanding to approximately 314 million shares as of April 10, 2012.

Purchase Price: Pursuant to the merger, all of the NSTAR common shares were exchanged at the fixed exchange ratio of 1.312 NU common shares for each NSTAR common share. The total consideration transferred in the merger was based on the closing price of NU common shares on April 9, 2012, the day prior to the date the merger was completed, and was calculated as follows:

NSTAR common shares outstanding as of April 9, 2012 (in thousands)*		103,696
Exchange ratio		1.312
NU common shares issued for NSTAR common shares outstanding (in thousands)		136,049
Closing price of NU common shares on April 9, 2012	$	36.79
Value of common shares issued (in millions)	$	5,005
Fair value of NU replacement stock-based compensation awards related to pre-merger service (in millions)		33
Total purchase price (in millions)	$	5,038

*

Includes 109 thousand shares related to NSTAR stock-based compensation awards that vested immediately prior to the merger

Certain of NSTAR s stock-based compensation awards, including deferred shares, performance shares and all outstanding stock options, were replaced with NU awards using the exchange ratio upon consummation of the merger. In accordance with accounting guidance for business combinations, the portion of the fair value of these awards attributable to service provided prior to the merger is included in the purchase price as it represents consideration transferred in the merger. See Note 10D, "Employee Benefits Share-Based Payments," for further information.

Purchase Price Allocation: The allocation of the total purchase price to the estimated fair values of the assets acquired and liabilities assumed has been determined based on the accounting guidance for fair value measurements, which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The allocation of the total purchase price includes adjustments to record the fair value of NSTAR s unregulated telecommunications business, regulatory assets not earning a return, lease agreements, long-term debt and the preferred stock of NSTAR Electric. The fair values of NSTAR's assets and liabilities were determined based on significant estimates and assumptions, including Level 3 inputs, that are judgmental in nature. These estimates and assumptions include the timing and amounts of projected future cash flows and discount rates reflecting risk inherent in future cash flows.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. The completed allocation of the purchase price is as follows:

(Billions of Dollars)		
Current Assets	$	0.7
Property Plant and Equipment, Net		5.1
Goodwill		3.2
Other Long-Term Assets, excluding Goodwill		2.1
Current Liabilities		(1.3)
Long-Term Liabilities		(2.7)
Long-Term Debt and Other Long-Term Obligations		(2.1)
Total Purchase Price	$	5.0

The goodwill from the merger with NSTAR of $3.2 billion has been assigned to NU's reporting units based on relative fair values. NU's reporting units consist of Electric Distribution, Electric Transmission and Natural Gas Distribution. See the "Goodwill" section below for the allocation of goodwill to each reporting unit.

Pro Forma Financial Information: The following unaudited pro forma financial information reflects the pro forma combined results of operations of NU and NSTAR and reflects the amortization of purchase price adjustments assuming the merger had taken place on January 1, 2011. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of NU.

(Pro forma amounts in millions, except per share amounts)	For the Years Ended December 31, 2012		For the Years Ended December 31, 2011	
Operating Revenues	$	7,004	$	7,361
Net Income Attributable to Controlling Interest		630		689
Basic EPS		2.00		2.20
Diluted EPS		1.99		2.19

Pro forma net income does not include potential cost savings associated with the merger. Pro forma net income also excludes certain non-recurring merger costs and costs related to the Connecticut and Massachusetts settlement agreements described below, with the following aggregate after-tax impacts:

(Millions of Dollars)	For the Years Ended December 31, 2012		2011	
Transaction and Other Costs	$	32	$	19
Settlement Agreement Impacts		60		-
Total After-Tax Non-Recurring Costs Excluded from Pro Forma Net Income Attributable to Controlling Interest	$	92	$	19

Regulatory Approvals: On February 15, 2012, NU and NSTAR reached comprehensive settlement agreements with the Massachusetts Attorney General and the DOER related to the merger. The Attorney General settlement agreement covered a variety of rate-making and rate design issues, including a base distribution rate freeze through 2015 for NSTAR Electric, NSTAR Gas and WMECO and $15 million, $3 million and $3 million in the form of rate credits to their respective customers. The settlement agreement reached with the DOER covered the same rate-making and rate design issues as the Attorney General's settlement agreement, as well as a variety of matters impacting the advancement of Massachusetts clean energy policy established by the Green Communities Act and Global Warming Solutions Act. On April 4, 2012, the DPU approved the settlement agreements and the merger of NU and NSTAR.

On March 13, 2012, NU and NSTAR reached a comprehensive settlement agreement with both the Connecticut Attorney General and the Connecticut Office of Consumer Counsel related to the merger. The settlement agreement covered a variety of matters, including a $25 million rate credit to CL&P customers, a CL&P base distribution rate freeze until December 1, 2014, and the establishment of a $15 million fund for energy efficiency and other initiatives to be disbursed at the direction of the DEEP. In the agreement, CL&P agreed to forego rate recovery of $40 million of the deferred storm restoration costs associated with restoration activities following Tropical Storm Irene and the October 2011 snowstorm. On April 2, 2012, the PURA approved the settlement agreement and the merger of NU and NSTAR.

The pre-tax financial impacts of the Connecticut and Massachusetts settlement agreements that were recognized by NU, CL&P, NSTAR Electric, and WMECO are summarized as follows:

(Millions of Dollars)	**NU**	**CL&P**	**NSTAR Electric**	**WMECO**
Customer Rate Credits	$ 46	$ 25	$ 15	$ 3
Storm Costs Deferral Reduction	40	40	-	-
Establishment of Energy Efficiency Fund	15	-	-	-
Total Pre-Tax Settlement Agreement Impacts	$ 101	$ 65	$ 15	$ 3

NSTAR Revenues and Net Income: The impact of NSTAR on NU's accompanying consolidated statement of income includes operating revenues of $1,957.8 million and net income attributable to controlling interest of $182.9 million for the year ended December 31, 2012.

Goodwill: In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with the accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. A loss is recognized if the implied fair value of a reporting unit's goodwill is less than the carrying value of its goodwill. NU uses October 1st as the annual goodwill impairment testing date.

On April 10, 2012, upon consummation of the merger with NSTAR, NU recorded approximately $3.2 billion of goodwill. With the completion of the NSTAR merger, NU reviewed its management structure and determined that the reporting units for the purpose of testing goodwill for impairment are Electric Distribution, Electric Transmission and Natural Gas Distribution. 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. Accordingly, the goodwill resulting from the NSTAR merger has been allocated to the Electric Distribution, Electric Transmission and Natural Gas Distribution reporting units based on the estimated fair values of the reporting units as of the merger date.

As of December 31, 2011, the only reporting unit that maintained goodwill was the natural gas reportable segment, related to the acquisition of the parent of Yankee Gas in 2000. This goodwill is recorded at Yankee Gas. The goodwill balance at Yankee Gas as of December 31, 2012 and 2011 was $0.3 billion.

NU completed its impairment analysis of the NSTAR and Yankee Gas goodwill balances as of October 1, 2012 and determined that no impairment exists. In completing this analysis, the fair value of the reporting units was estimated using a discounted cash flow methodology and a market method utilizing comparable company information and market transactions.

The allocation of goodwill to NU's reporting units is as follows:

	Electric Distribution	Electric Transmission	Natural Gas Distribution	Total
Balance as of December 31, 2011	$ -	$ -	$ 0.3	$ 0.3
Merger with NSTAR	2.5	0.6	0.1	3.2
Balance as of December 31, 2012	$ 2.5	$ 0.6	$ 0.4	$ 3.5

3.

REGULATORY ACCOUNTING

On April 10, 2012, NSTAR's regulated utility subsidiaries, NSTAR Electric and NSTAR Gas, became subsidiaries of NU. For NSTAR Electric, certain regulatory asset and liability balances as of December 31, 2011 have been reclassified to the current year presentation in order to align the reporting of regulatory activities subsequent to the closing of the merger.

NU's Regulated companies continue to be rate-regulated on a cost-of-service basis; therefore, the accounting policies of the Regulated companies apply GAAP applicable to rate-regulated enterprises and 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 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)	**2012**	**2011**
Benefit Costs	$ 2,452.1	$ 1,360.5
Regulatory Assets Offsetting Derivative Liabilities	885.6	939.6
Goodwill	537.6	-
Storm Restoration Costs	547.7	356.0
Income Taxes, Net	516.2	425.4
Securitized Assets	232.6	101.8
Contractual Obligations	217.6	100.9
Power Contracts Buy Out Agreements	92.9	8.6
Regulatory Tracker Deferrals	190.1	45.9
Asset Retirement Obligations	88.8	47.5
Other Regulatory Assets	76.2	136.6
Total Regulatory Assets	$ 5,837.4	$ 3,522.8
Less: Current Portion	$ 705.0	$ 255.1
Total Long-Term Regulatory Assets	$ 5,132.4	$ 3,267.7

	As of December 31,							
	2012				**2011**			
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric**[1]	**PSNH**	**WMECO**
Benefit Costs	$ 563.2	$ 781.2	$ 223.7	$ 116.0	$ 572.8	$ 813.7	$ 200.0	$ 118.9
Regulatory Assets Offsetting Derivative Liabilities	866.2	14.9	-	3.0	932.0	3.4	-	7.3
Goodwill	-	461.5	-	-	-	478.9	-	-
Storm Restoration Costs	413.9	55.8	34.5	43.5	268.3	30.6	44.0	43.7
Income Taxes, Net	367.5	47.1	36.2	31.0	339.6	48.8	38.0	17.8
Securitized Assets	-	205.1	19.7	7.8	-	368.5	76.4	25.4
Contractual Obligations	64.0	22.8	-	14.9	80.9	30.8	-	20.0
Power Contracts Buy Out Agreements	-	85.9	7.0	-	-	109.5	8.6	-
Regulatory Tracker Deferrals	12.2	71.4	49.3	31.9	5.5	61.1	11.9	22.1
Asset Retirement Obligations	29.4	29.4	14.2	3.5	27.9	24.5	13.5	3.2
Other Regulatory Assets	27.9	16.9	29.4	12.6	47.0	34.7	35.7	10.3
Total Regulatory Assets	$ 2,344.3	$ 1,792.0	$ 414.0	$ 264.2	$ 2,274.0	$ 2,004.5	$ 428.1	$ 268.7
Less: Current Portion	$ 185.9	$ 347.1	$ 62.9	$ 42.4	$ 170.2	$ 323.9	$ 34.2	$ 35.5

Total Long-Term Regulatory Assets	$ 2,158.4	$ 1,444.9	$ 351.1	$ 221.8	$ 2,103.8	$ 1,680.6	$ 393.9	$ 233.2

(1)

NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011.

Regulatory Costs Not Yet Approved: Additionally, the Regulated companies had $69.9 million ($3.9 million for CL&P, $25.4 million for NSTAR Electric, $35.7 million for PSNH, and $1.4 million for WMECO) and $32.4 million ($5 million for CL&P, $22.4 million for PSNH, and $1.6 million for WMECO) of regulatory costs as of December 31, 2012 and 2011, respectively, which were included in Other Long-Term Assets on the accompanying consolidated balance sheets. For comparative purposes, NSTAR Electric had $9.5 million of such regulatory costs as of December 31, 2011. These amounts represent incurred costs that have not yet been approved for recovery by the applicable regulatory agency. Management believes it is probable that recovery of these costs will ultimately be approved.

For PSNH, of the total December 31, 2012 regulatory costs not yet approved, $12.1 million related to costs incurred for the 2012 Hurricane Sandy storm and $22.3 million related to costs incurred for the 2011 Tropical Storm Irene and the October snowstorm restorations that met the NHPUC criteria for cost deferral. As of December 31, 2011, the storm restoration costs incurred for the 2011 Tropical Storm Irene and the October snowstorm restorations totaled $21.7 million. Refer to the "*Storm Restoration Costs*" section below for further discussion. The NSTAR Electric balance as of December 31, 2012 and 2011 related to costs deferred in connection with the basic service bad debt adder. See Note 12H, "Commitments and Contingencies Basic Service Bad Debt Adder," for further information.

Equity Return on Regulatory Assets: For rate-making purposes, the Regulated companies recover the carrying cost, including an allowed equity return, on certain regulatory assets. This equity return, which is not recorded on the accompanying consolidated balance sheets, totaled $2.5 million and $3.5 million for CL&P and $21.8 million and $7.6 million for PSNH as of December 31, 2012 and 2011, respectively. These carrying costs will be recovered in future rates.

Regulatory Assets - The following provides further information about regulatory assets:

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 recover these costs from customers through rates, regulatory assets are recorded as an offset for the liability that is recognized for the funded status of the pension and postretirement plans. Regulatory accounting was also applied to the portions of the NUSCO and NSTAR Electric & Gas costs that support the Regulated companies, as these amounts are also recoverable. CL&P and PSNH do not collect carrying charges on these deferred benefit costs regulatory assets. WMECO's deferred benefit costs regulatory assets are earning a return at the same rate as the assets included in rate base. NSTAR Electric does not earn a return on the regulatory assets recorded to offset the funded status.

NSTAR Electric and WMECO each recover their qualified pension and postretirement expenses through rate reconciling mechanisms that fully track the change in net pension and postretirement expenses each year. CL&P and

PSNH will recover benefit costs through rates as allowed by their applicable regulatory commissions. NSTAR Electric earns a carrying charge on the excess cumulative benefit plan trust fund contributions it has made over what it has cumulatively recognized as net periodic benefit expense, net of deferred income taxes. As of December 31, 2012 and 2011, these balances were $366.8 million and $428 million of the benefit costs regulatory asset, 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. See Note 5, "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.

Goodwill: Goodwill that originated from the merger that created NSTAR in 1999 is recoverable in rates over the remaining 27 year amortization period, without a carrying charge.

Storm Restoration Costs: The storm restoration cost deferrals relate to costs incurred at CL&P, NSTAR Electric, PSNH and WMECO for restorations that the Company expects to collect from customers. A storm must meet certain criteria to be declared a major storm with the criteria specific to each state jurisdiction and utility company. Once a storm is declared major, all qualifying expenses incurred during storm restoration efforts, if deemed prudent, are deferred and recovered from customers in future periods. In Connecticut, qualifying storm restoration costs must exceed $5 million for a storm to be declared a major storm. In Massachusetts, qualifying storm restoration costs must exceed $1 million for NSTAR Electric and $300,000 for WMECO and an emergency response plan must be initiated for a storm to be declared a major storm. In New Hampshire, (1) at least 10 percent of customers must be without power with at least 200 concurrent locations requiring repairs (trouble spots), or (2) at least 300 concurrent trouble spots must be reported for a storm to be declared a major storm.

In 2011, Tropical Storm Irene and the October snowstorm each caused extensive damage to NU s distribution system. As of December 31, 2012 and 2011, CL&P had recorded total deferred storm restoration costs relating to Tropical Storm Irene and the October 2011 snowstorm as a regulatory asset of $281.6 million and $263.3 million, respectively. The CL&P storm restoration cost regulatory asset balance includes a reserve of $40 million recorded in connection with the Connecticut settlement agreement. See Note 2, "Merger of NU and NSTAR," for further information. As of December 31, 2012 and 2011, NSTAR Electric had recorded total deferred storm restoration costs for these 2011 storms of $35.8 million and $35.8 million, respectively, and WMECO had recorded $26.5 million and $26.7 million, respectively, as regulatory assets. PSNH recorded $22.3 million and $21.7 million for these 2011 storms in Other Long-Term Assets, as of December 31, 2012 and 2011, respectively, as previously described.

On August 1, 2012, PURA issued a final decision in the investigation of CL&P s performance related to both Tropical Storm Irene and the October 2011 snowstorm. The decision concluded that CL&P was deficient and inadequate in its preparation, response, and communication to both storms, and identified certain penalties that could be imposed on CL&P during its next rate case, including a reduction in allowed regulatory ROE and the disallowance of certain deferred storm restoration costs. However, PURA will consider and weigh the extent to which CL&P has taken steps in its restructuring of storm management and the establishment of new practices for execution in future storm response in determining any potential penalties. CL&P believes such steps to improve current storm preparation and response practices have been successfully executed in recent storms. At this time, management cannot estimate the impact on CL&P s financial position, results of operations or cash flows. CL&P continues to believe that its response to these 2011 storms was prudent, was consistent with industry standards, and that it is probable that it will be able to recover its deferred costs.

See Note 12E, "Commitments and Contingencies DPU Penalties for 2011 Storm Responses," for a discussion of NSTAR Electric and WMECO's 2011 storm response.

On October 29, 2012, Hurricane Sandy caused extensive damage to NU s electric distribution system across all three states. The cost of restoration that was deferred for future recovery from customers and recorded as a regulatory asset as of December 31, 2012 for CL&P, NSTAR Electric, and WMECO totaled $159.9 million, $27.8 million and $4.2 million, respectively. PSNH recorded $12.1 million in Other-Long Term Assets, as previously described. Management believes its response to the storm damage was prudent and therefore believes it is probable that CL&P, NSTAR Electric, PSNH and WMECO will be allowed to recover these deferred storm restoration costs. Accordingly, the storm did not have a material impact to the results of operations of CL&P, NSTAR Electric, PSNH or WMECO. Each operating company will seek recovery of these deferred storm restoration costs through its applicable regulatory recovery process.

The PSNH storm restoration costs deferral as of December 31, 2012 and 2011 related to costs incurred for a major storm in December 2008 and the February 2010 wind storm, both of which were approved for recovery and are included in rate base.

Income Taxes, Net: The tax effect of temporary book-tax 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. As these assets are offset by deferred income tax liabilities, no carrying charge is collected. For further information regarding income taxes, see Note 11, "Income Taxes," to the consolidated financial statements.

Securitized Assets: In March 2005, NSTAR Electric issued $674.5 million RRBs and used the majority of the proceeds from that issuance to effect purchase power contract buyouts. The collateralized amounts reflected as securitized regulatory assets for NSTAR Electric as of December 31, 2012 and 2011 were $14.1 million and $98.4 million, respectively. In April 2001, PSNH issued $525 million RRBs and 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 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. NSTAR Electric RRBs are scheduled to fully amortize by March 15, 2013, PSNH RRBs are scheduled to fully amortize by May 1, 2013, and WMECO RRBs are scheduled to fully amortize by June 1, 2013.

NSTAR Electric's remaining balance primarily includes other costs related to purchase power contract divestitures and certain costs related to NSTAR Electric s former generation business that are recovered with a return through the transition charge and amounted to $186.1 million and $259.8 million as of December 31, 2012 and 2011, respectively. These cost recoveries primarily occur through September 2016 for NSTAR Electric and are subject to adjustment by the DPU.

Contractual Obligations: Under the terms of contracts with CYAPC, YAEC and MYAPC, CL&P, NSTAR Electric, 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 contractual obligations regulatory assets. These obligations for CL&P are earning a return and are being recovered through the CTA. Amounts for NSTAR Electric are being recovered without a return through the transition charge and are anticipated to be recovered by 2015. 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. As a result of the April 10, 2012 merger with NSTAR and consolidation of CYAPC and YAEC, NU's regulatory asset balance also includes the regulatory assets of CYAPC and YAEC, which amounted to $214 million as of December 31, 2012. At the NU consolidated level, intercompany transactions between CL&P, NSTAR Electric, PSNH and WMECO and the CYAPC and YAEC companies are eliminated in consolidation.

Power Contracts Buy Out Agreements: NSTAR Electric's balance represents the recorded contract termination liability related to certain purchase power contract buy out agreements that NSTAR Electric executed in 2004 and their future recovery through NSTAR Electric s transition charge. NSTAR Electric does not earn a return on this regulatory asset. The contracts termination payments will occur over time and will be collected from customers through NSTAR Electric s transition charge over the same time period. The cost recovery period of these terminated contracts is through September 2016. PSNH's balance represents payments associated with the termination of various power purchase contracts that were recorded as regulatory assets and are amortized over the remaining life of the contracts.

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 a return. The following regulatory reconciliation mechanisms were recorded as either regulatory assets or liabilities as of December 31, 2012 and 2011:

CL&P: 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 had also established an obligation to refund the variable incentive portion of its transition service procurement fee, which totaled $26.3 million as of December 31, 2011 and was recorded as a regulatory liability. During 2012, PURA issued a decision approving a joint settlement agreement submitted October 2, 2012, by CL&P, UI, and the Connecticut Consumer Counsel, in resolution of all issues associated with the procurement incentive for 2004, 2005 and 2006. Under the joint settlement agreement, CL&P refunded to customers $5.7 million of funds collected and associated interest. CL&P will be allowed to retain approximately $11.5 million of procurement incentive along with the remaining accrued interest that it was not required to refund to customers.

NSTAR Electric and WMECO: Each company recovers certain of its costs on a fully reconciling basis through DPU-approved cost recovery mechanisms. These rate mechanisms recover costs associated with the procurement of energy for basic service, the retail transmission of energy, costs associated with electric industry restructuring, pension and postretirement benefits, and energy efficiency programs. Costs associated with industry restructuring include RRB debt service, nuclear decommissioning costs and above-market IPP costs. In addition, WMECO recovers costs associated with its investments in renewable energy, such as solar projects and credits given to customers who generate renewable energy.

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.

PSNH: 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.

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, NSTAR Electric 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.

Other Regulatory Assets: Other Regulatory Assets primarily include environmental remediation costs, losses associated with the reacquisition or redemption of long-term debt, and 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, partially offset by purchase price adjustments recorded in connection with the merger with NSTAR reflected in regulatory assets.

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

NU	**As of December 31,**			
(Millions of Dollars)		**2012**		**2011**
Cost of Removal	$	440.8	$	172.2
Regulatory Tracker Deferrals		95.1		139.1
AFUDC Transmission Incentive		70.0		67.0
Spent Nuclear Fuel Costs and Contractual Obligations		15.4		15.4
Other Regulatory Liabilities		53.0		40.2
Total Regulatory Liabilities	$	674.3	$	433.9
Less: Current Portion	$	134.1	$	167.8
Total Long-Term Regulatory Liabilities	$	540.2	$	266.1

	As of December 31,							
	2012				2011			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric (1)	PSNH	WMECO
Cost of Removal	$ 44.2	$ 240.3	$ 51.2	$ -	$ 63.8	$ 235.8	$ 53.2	$ 7.2
Regulatory Tracker Deferrals	39.1	14.4	20.4	13.7	94.4	11.7	17.3	21.3
AFUDC Transmission Incentive	56.6	4.1	-	9.3	57.7	4.3	-	9.3
Spent Nuclear Fuel Costs and Contractual Obligations	15.4	-	-	-	15.4	-	-	-
Wholesale Transmission Overcollections	-	-	-	5.3	4.5	-	2.6	9.5
Other Regulatory Liabilities	1.1	32.9	3.8	2.4	11.8	29.7	5.8	2.4
Total Regulatory Liabilities	$ 156.4	$ 291.7	$ 75.4	$ 30.7	$ 247.6	$ 281.5	$ 78.9	$ 49.7
Less: Current Portion	$ 32.1	$ 47.5	$ 23.0	$ 21.0	$ 108.3	$ 41.6	$ 24.5	$ 33.1
Total Long-Term Regulatory Liabilities	$ 124.3	$ 244.2	$ 52.4	$ 9.7	$ 139.3	$ 239.9	$ 54.4	$ 16.6

(1)

NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011.

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. The estimated cost to remove utility assets from service is recognized as a component of depreciation expense and the cumulative amounts collected from customers but not yet expended is recognized as a regulatory liability. Expended costs that exceed amounts collected from customers are recognized as regulatory assets, as they are probable of recovery in future rates.

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. NSTAR Electric recorded AFUDC on reliability-related projects over $5 million through December 31, 2012, 50 percent of which was reserved as a regulatory liability to reflect rate base recovery for 50 percent of the CWIP as a result of FERC-approved transmission incentives.

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, NSTAR Electric, 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 are recorded for collections in excess of costs. Regulatory assets are recorded for costs in excess of collections, as they are probable of recovery in future rates.

Other Regulatory Liabilities: Other Regulatory Liabilities primarily includes amounts that are subject to various rate reconciling mechanisms that, as of each period end date, would result in refunds to customers.

4.

PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

Utility property, plant and equipment is recorded at original cost. Original cost includes materials, labor, construction overhead and AFUDC for regulated property. The cost of repairs and maintenance, including planned major maintenance activities, is charged to Operating Expenses as incurred.

The following tables summarize the NU, CL&P, NSTAR Electric, PSNH and WMECO investments in utility property, plant and equipment by asset category:

NU	**As of December 31,**	
(Millions of Dollars)	**2012**	**2011**
Distribution Electric	$ 11,438.2	$ 6,540.4
Distribution - Natural Gas	2,274.2	1,247.6
Transmission	5,541.1	3,541.9
Generation	1,146.6	1,096.0
Electric and Natural Gas Utility	20,400.1	12,425.9
Other [(1)]	429.3	305.1
Property, Plant and Equipment, Gross	20,829.4	12,731.0
Less: Accumulated Depreciation		
Electric and Natural Gas Utility	(5,065.1)	(3,035.5)
Other	(171.5)	(120.2)
Total Accumulated Depreciation	(5,236.6)	(3,155.7)
Property, Plant and Equipment, Net	15,592.8	9,575.3
Construction Work in Progress	1,012.2	827.8
Total Property, Plant and Equipment, Net	$ 16,605.0	$ 10,403.1

(1)

These assets represent unregulated property and are primarily comprised of building improvements at RRR and software and equipment at NUSCO as of December 31, 2012 and 2011, and telecommunications equipment at NSTAR Communications, Inc. as of December 31, 2012.

As of December 31,	
2012	**2011**

(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric(1)	PSNH	WMECO
Distribution	$ 4,691.3	$ 4,539.9	$ 1,520.1	$ 724.2	$ 4,419.6	$ 4,334.4	$ 1,451.6	$ 704.3
Transmission	2,796.1	1,529.7	599.2	583.7	2,689.1	1,386.9	546.4	297.4
Generation	-	-	1,125.5	21.1	-	-	1,074.8	21.2
Property, Plant and Equipment, Gross	7,487.4	6,069.6	3,244.8	1,329.0	7,108.7	5,721.3	3,072.8	1,022.9
Less: Accumulated Depreciation	(1,698.1)	(1,540.1)	(954.0)	(252.1)	(1,596.7)	(1,436.0)	(893.6)	(240.5)
Property, Plant and Equipment, Net	5,789.3	4,529.5	2,290.8	1,076.9	5,512.0	4,285.3	2,179.2	782.4
Construction Work in Progress	363.7	205.8	61.7	213.6	315.4	162.0	77.5	295.4
Total Property, Plant and Equipment, Net	$ 6,153.0	$ 4,735.3	$ 2,352.5	$ 1,290.5	$ 5,827.4	$ 4,447.3	$ 2,256.7	$ 1,077.8

(1)

NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011.

Depreciation of utility assets is calculated on a straight-line basis using composite rates based on the estimated remaining useful lives of the various classes of property (estimated useful life for PSNH distribution). The composite rates are subject to approval by the appropriate state regulatory agency. The composite rates include a cost of removal component, which is collected from customers during the life of the property and is recognized as a regulatory liability. Depreciation rates are applied to property from the time it is placed in service.

Upon retirement from service, the cost of the utility asset is charged to the accumulated provision for depreciation. The actual incurred removal costs are applied against the related regulatory liability.

The depreciation rates for the various classes of utility property, plant and equipment aggregate to composite rates as follows:

(Percent)	2012	2011	2010
NU	2.5	2.6	2.7

CL&P	2.5	2.4	2.7
NSTAR Electric	2.8	3.0	3.0
PSNH	3.0	2.9	2.8
WMECO	3.3	2.9	2.8

The following table summarizes average useful lives of depreciable assets:

	Average Depreciable Life				
(Years)	**NU**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**
Distribution	42.1	41.8	33.9	33.8	30.2
Transmission	45.3	39.8	46.3	42.1	47.5
Generation	32.7	-	-	32.8	25.0
Other	16.7	-	-	-	-

5.

DERIVATIVE INSTRUMENTS

The Regulated companies purchase and procure energy and energy-related products for their customers, which are subject to price volatility. The costs associated with supplying energy to customers are recoverable through customer rates. The Regulated companies manage the risks associated with the price volatility of energy and energy-related products through the use of derivative contracts, many of which meet the definition of and are designated as "normal purchases or normal sales" (normal) under the applicable accounting guidance, and the use of nonderivative contracts.

Derivative contracts that are not recorded as normal 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 costs are, and management believes they will continue to be, recovered from or refunded in customers rates. For NU's remaining unregulated wholesale marketing contracts, changes in fair values of derivatives are included in Net Income. The costs and benefits of derivative contracts that meet the definition of 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.

CL&P, NSTAR Electric 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 and are accounted for as normal. CL&P, NSTAR Electric and WMECO have entered into derivative and nonderivative contracts for the purchase of energy and energy-related products and contracts that are derivatives. NU also has NYMEX future contracts in order to reduce variability associated with the purchase price of approximately 11.5 million MMBtu of natural gas.

The costs or benefits from all of the Regulated companies' derivative contracts are recoverable from or refundable to customers, and therefore, changes in fair value are recorded as Regulatory Assets or Regulatory Liabilities on the accompanying consolidated balance sheets.

NU, through Select Energy, has one remaining fixed price forward sales contract that expires on December 31, 2013 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 several forward purchase contracts. The contracts are accounted for at fair value, and changes in their fair values are recorded in Purchased Power, Fuel and Transmission on the accompanying consolidated statements of income.

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 categorized by risk type and the net amounts recorded as current or long-term derivative asset or liability:

	As of December 31, 2012		
(Millions of Dollars)	Commodity Supply and Price Risk Management	Collateral and Netting [1]	Net Amount Recorded as Derivative Asset/(Liability) [2]
Current Derivative Assets:			
Level 2:			
Other	$ 0.2	$ -	$ 0.2
Level 3:			
CL&P	17.7	(12.0)	5.7
Other	5.5	-	5.5
Total Current Derivative Assets	$ 23.4	$ (12.0)	$ 11.4
Long-Term Derivative Assets:			
Level 3:			
CL&P	$ 159.7	$ (69.1)	$ 90.6
Total Long-Term Derivative Assets	$ 159.7	$ (69.1)	$ 90.6
Current Derivative Liabilities:			
Level 2:			
Other	$ (19.9)	$ 0.6	$ (19.3)
Level 3:			
CL&P	(96.9)	-	(96.9)
NSTAR Electric	(1.0)	-	(1.0)
Total Current Derivative Liabilities	$ (117.8)	$ 0.6	$ (117.2)
Long-Term Derivative Liabilities:			
Level 2:			
Other	$ (0.2)	$ -	$ (0.2)
Level 3:			
CL&P	(865.6)	-	(865.6)
NSTAR Electric	(13.9)	-	(13.9)
WMECO	(3.0)	-	(3.0)
Total Long-Term Derivative Liabilities	$ (882.7)	$ -	$ (882.7)

	As of December 31, 2011		
(Millions of Dollars)	Commodity Supply and Price Risk Management	Collateral and Netting [1]	Net Amount Recorded as Derivative Asset/(Liability) [2]
Current Derivative Assets:			

Level 3:						
CL&P	$	17.9	$	(11.6)	$	6.3
Other		4.7		-		4.7
Total Current Derivative Assets [3]	$	22.6	$	(11.6)	$	11.0
<u>Long-Term Derivative Assets:</u>						
Level 3:						
CL&P	$	174.2	$	(80.4)	$	93.8
Other		4.6		-		4.6
Total Long-Term Derivative Assets	$	178.8	$	(80.4)	$	98.4
<u>Current Derivative Liabilities:</u>						
Level 3:						
CL&P	$	(95.9)	$	-	$	(95.9)
WMECO		(0.1)		-		(0.1)
Other		(16.1)		4.5		(11.6)
Total Current Derivative Liabilities	$	(112.1)	$	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 (4)	$	(960.3)	$	0.4	$	(959.9)

(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. NSTAR Electric and WMECO derivative liabilities are included in Other Current Liabilities and Other Long-Term Liabilities on their accompanying consolidated balance sheets.

(3)

In addition to the amounts reflected in the table, as of December 31, 2011, NU had $2.3 million of hedging instruments that were classified as Level 2 in the fair value hierarchy, which related to a fair value hedge that expired on April 2, 2012 and was included in Prepayments and Other Current Assets on the accompanying consolidated balance sheet.

(4)

As of December 31, 2011, NSTAR Electric had $3.4 million of derivative liabilities classified as Level 3 within the fair value hierarchy and included in Other Long-Term Liabilities on the accompanying NSTAR Electric consolidated balance sheet. These amounts are not included in NU consolidated as of December 31, 2011.

The business activities of the Company that resulted in the recognition of derivative assets also create exposure to various counterparties. As of December 31, 2012, NU and CL&P's derivative assets are exposed to counterparty credit risk. Of these amounts, $96.5 million and $96.3 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 1H, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 1I, "Summary of Significant Accounting Policies - Derivative Accounting," to the consolidated financial statements.

Derivatives Not Designated as Hedges

Commodity Supply and Price Risk Management: As 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 extend through 2026 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. In addition, CL&P has a contract to purchase 0.1 million MWh of energy per year through 2020.

NSTAR Electric has a renewable energy contract to purchase 0.1 million MWh of energy per year through 2018. NSTAR Electric also has a capacity related contract for up to 35 MW that extends through 2019.

WMECO has a renewable energy contract to purchase 0.1 million MWh of energy per year through 2028 with a facility that is expected to achieve commercial operation by November 2013.

As of December 31, 2012 and 2011, NU had approximately 24 thousand MWh and 123 thousand MWh, respectively, of supply volumes remaining in its unregulated wholesale portfolio when expected sales are compared with supply contracts.

The following table presents the realized and unrealized gains/(losses) associated with NU s derivative contracts not designated as hedges (See Level 3 tables in the "Valuations using significant unobservable inputs" section for CL&P, NSTAR Electric and WMECO gains and losses on derivative contracts):

Location of Amounts Recognized on Derivatives	**Amounts Recognized on Derivatives For the Years Ended December 31,**		
(Millions of Dollars)	**2012**	**2011**	**2010**
NU			
Balance Sheet:			
Regulatory Assets	$ (29.0)	$ (162.0)	$ (95.7)
Statement of Income:			
Purchased Power, Fuel and Transmission	(0.7)	0.5	2.7

Hedging Instruments

Fair Value Hedge: NU parent had a fixed to floating interest rate swap on its $263 million, fixed rate senior note that matured on April 1, 2012. This interest rate swap qualified and was designated as a fair value hedge. Prior to the settlement of the swap on April 2, 2012, $2.5 million of interest benefit was recorded in Net Income in the first quarter of 2012. For the years ended December 31, 2011 and 2010, $10.5 million and $10.9 million of interest benefit was recorded in Net Income, respectively.

Cash Flow Hedges: In 2011, PSNH and WMECO settled interest rate swaps associated with $280 million and $50 million, respectively, of long-term debt issuances and as a result PSNH and WMECO recorded pre-tax reductions of $18.2 million and $6.9 million, respectively, to AOCI that are being amortized over the remaining lives of the associated debt. In addition, NU, CL&P, PSNH and WMECO continue to amortize interest rate swaps settled in prior years from AOCI into Interest Expense over the remaining life of the associated long-term debt. The pre-tax impact of cash flow hedging instruments on AOCI is as follows:

Gains/(Losses) Recognized on	**Gains/(Losses) Reclassified from AOCI**

(Millions of Dollars)	**Derivative Instruments For the Year Ended December 31, 2011**	**into Interest Expense For the Years Ended December 31, 2012**	**2011**	**2010**
NU	$ (25.1)	$ (3.3)	$ (1.3)	$ (0.4)
CL&P	-	(0.7)	(0.7)	(0.7)
PSNH	(18.2)	(2.0)	(0.8)	(0.2)
WMECO	(6.9)	(0.5)	(0.1)	0.1

For further information, see Note 15, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

Credit Risk

Certain of NU s contracts contain credit risk contingent features. These features require NU to maintain investment grade credit ratings from the major rating agencies and to post collateral for contracts in a net liability position over specified credit limits. The following summarizes the fair value of derivative contracts that were in a net liability position and subject to credit risk contingent features, the fair value of cash collateral, and the additional collateral that would be required to be posted by NU if the unsecured debt credit ratings of NU parent were downgraded to below investment grade as of December 31, 2012 and 2011:

	As of December 31, 2012			As of December 31, 2011		
(Millions of Dollars)	**Fair Value Subject to Credit Risk Contingent Features**	**Cash Collateral Posted**	**Additional Collateral Required if Downgraded Below Investment Grade**	**Fair Value Subject to Credit Risk Contingent Features**	**Cash Collateral Posted**	**Additional Collateral Required if Downgraded Below Investment Grade**
NU	$ (15.3)	$ -	$ 17.4	$ (23.5)	$ 4.1	$ 19.9

Fair Value Measurements of Derivative Instruments

Valuation of Derivative Instruments: Derivative contracts classified as Level 2 in the fair value hierarchy relate to the financial contracts for natural gas futures and the remaining unregulated wholesale marketing sourcing contracts to purchase energy for periods in which prices are quoted in an active market. Prices are obtained from broker quotes and are 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.

The fair value of derivative contracts classified as Level 3 utilize significant unobservable inputs. The fair value is modeled using income techniques, such as discounted cash flow approaches adjusted for assumptions relating to exit price. Significant observable inputs for valuations of these contracts include energy and energy-related product prices in future years for which quoted prices in an active market exist. Fair value measurements categorized in Level 3 of the fair value hierarchy are prepared by individuals with expertise in valuation techniques, pricing of energy and energy-related products, and accounting requirements. The future power and capacity prices for periods that are not quoted in an active market or established at auction are based on available market data and are escalated based on estimates of inflation to address the full time period of the contract.

Valuations of derivative contracts using discounted cash flow methodology include assumptions regarding the timing and likelihood of scheduled payments and also reflect non-performance 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. Valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using historical market transactions adjusted for the terms of the contract.

The following is a summary of NU s, including CL&P s, NSTAR Electric s and WMECO s, Level 3 derivative contracts and the range of the significant unobservable inputs utilized in the valuations over the duration of the contracts:

	Range	**Period Covered**
Energy Prices:		
NU	$43 - $90 per MWh	2018 - 2028
CL&P	$50 - $55 per MWh	2018 - 2020
WMECO	$43 - $90 per MWh	2018 - 2028
Capacity Prices:		
NU	$1.40 - $10.53 per kW-Month	2016 - 2028
CL&P	$1.40 - $9.83 per kW-Month	2016 - 2026
NSTAR Electric	$1.40 - $3.39 per kW-Month	2016 - 2019
WMECO	$1.40 - $10.53 per kW-Month	2016 - 2028
Forward Reserve:		
NU, CL&P	$0.35 - $0.90 per kW-Month	2013 - 2024
REC Prices:		
NU	$25 - $85 per REC	2013 - 2028
NSTAR Electric	$25 - $71 per REC	2013 - 2018
WMECO	$25 - $85 per REC	2013 - 2028

Exit price premiums of 11 percent through 32 percent are also applied on these contracts and reflect the most recent market activity available for similar type contracts.

Significant increases or decreases in future power or capacity prices in isolation would decrease or increase, respectively, the fair value of the derivative liability. Any increases in the risk premiums would increase the fair value of the derivative liabilities. Changes in these fair values are recorded as a regulatory asset or liability and would not impact net income.

Valuations using significant unobservable inputs: The following tables present changes for the years ended December 31, 2012 and 2011, 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 fair value as of January 1, 2012 reflects a reclassification of remaining unregulated wholesale marketing sourcing contracts that had previously been presented as a portfolio along with the unregulated wholesale marketing sales contract as Level 3 under the highest and best use valuation premise. These contracts are now classified within Level 2 of the fair value hierarchy.

(Millions of Dollars)		**NU**		**CL&P**		**NSTAR Electric**[1]		**WMECO**
Derivatives, Net:								
Fair Value as of January 1, 2011	$	(840.2)	$	(806.1)	$	(2.4)	$	-
Net Realized/Unrealized Gains/(Losses) Included in:								
Net Income		0.5		-		-		-
Regulatory Assets		(161.0)		(153.6)		(4.3)		(7.3)
Settlements		38.5		28.1		3.3		-
Fair Value as of December 31, 2011	$	(962.2)	$	(931.6)	$	(3.4)	$	(7.3)
Liabilities Assumed due to Merger with NSTAR		(5.4)		-		-		-
Transfer to Level 2		32.2		-		-		-
Net Realized/Unrealized Gains/(Losses) Included in:								
Net Income [2]		10.9		-		-		-
Regulatory Assets		(29.2)		(21.6)		(15.2)		4.3
Settlements		75.1		87.0		3.7		-
Fair Value as of December 31, 2012	$	(878.6)	$	(866.2)	$	(14.9)	$	(3.0)

(1)

NSTAR Electric amounts are included in NU consolidated from the date of the merger, April 10, 2012, through December 31, 2012. NSTAR Electric amounts are not included in NU consolidated for the year ended December 31, 2011.

(2)

The Net Income impact for the year ended December 31, 2012 relates to the unregulated wholesale marketing sales contract and is offset by the gains/(losses) on the unregulated sourcing contracts classified as Level 2 in the fair value hierarchy, resulting in total net losses of $0.7 million.

6.

MARKETABLE SECURITIES (NU, WMECO)

NU maintains a supplemental benefit trust to fund certain of NU s non-qualified executive retirement benefit obligations and WMECO maintains a spent nuclear fuel trust to fund WMECO s prior period spent nuclear fuel liability, each of which hold marketable securities. These trusts are not subject to regulatory oversight by state or federal agencies. As of April 10, 2012, upon consummation of the merger with NSTAR and consolidation of CYAPC and YAEC, NU's marketable securities also includes legally restricted trusts for the decommissioning of nuclear power plants.

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 mutual funds is reflected in Net Income. These mutual funds, classified as Level 1 in the fair value hierarchy, totaled $47 million and $41.1 million as of December 31, 2012 and 2011, respectively, and are included in current Marketable Securities. Net gains on these securities of $5.9 million and net losses of $1.1 million for the years ended December 31, 2012 and 2011, respectively, were recorded in Other Income, Net on the accompanying consolidated statements of income. Dividend income is recorded when dividends are declared and is 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, WMECO's spent nuclear fuel trust and CYAPC and YAEC's nuclear decommissioning trusts. 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, 2012			
(Millions of Dollars)	Amortized Cost	Pre-Tax Unrealized Gains[1]	Pre-Tax Unrealized Losses[1]	Fair Value
NU				
Debt Securities [2]	$ 266.6	$ 13.3	$ (0.1)	$ 279.8
Equity Securities [2]	145.5	20.0	-	165.5
WMECO				
Debt Securities	57.7	0.1	(0.1)	57.7

	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

(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.

(2)

NU's December 31, 2012 amounts include CYAPC's and YAEC's marketable securities held in nuclear decommissioning trusts of $340.4 million, the majority of which are legally restricted and can only be used for the decommissioning of the nuclear power plants owned by these companies. Unrealized gains and losses for the nuclear decommissioning trusts are offset in Other Long-Term Liabilities on the accompanying consolidated balance sheet. All of the equity securities accounted for as available-for-sale securities are held in these trusts.

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, the WMECO spent nuclear fuel trust, and in the trusts held by CYAPC and YAEC. 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 are recorded in Other Income, Net for the NU supplemental benefit trust, Other Long-Term Assets for the WMECO spent nuclear fuel trust, and offset in Other Long-Term Liabilities for CYAPC and YAEC. 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 and the CYAPC and YAEC nuclear decommissioning trusts to compute the realized gains and losses on the sale of available-for-sale securities.

Contractual Maturities: As of December 31, 2012, 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 [1]	$ 66.6	$ 66.6	$ 27.4	$ 27.4

One to five years	57.3	58.7	17.5	17.5
Six to ten years	51.2	54.6	6.0	6.1
Greater than ten years	91.5	99.9	6.8	6.7
Total Debt Securities	$ 266.6	$ 279.8	$ 57.7	$ 57.7

(1)

Amounts in the Less than one year NU category include securities in the nuclear decommissioning trusts, which are restricted and are classified in long-term Marketable Securities on the accompanying consolidated balance sheet.

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		**WMECO**	
	As of December 31,		**As of December 31,**	
(Millions of Dollars)	**2012**	**2011**	**2012**	**2011**
Level 1:				
Mutual Funds and Equities	$ 212.5	$ 41.1	$ -	$ -
Money Market Funds	40.2	1.8	5.2	0.1
Total Level 1	$ 252.7	$ 42.9	$ 5.2	$ 0.1
Level 2:				
U.S. Government Issued Debt Securities				
(Agency and Treasury)	69.9	11.1	18.7	8.0
Corporate Debt Securities	33.0	16.5	7.0	9.1
Asset-Backed Debt Securities	28.5	25.9	10.9	7.9
Municipal Bonds	93.8	16.1	11.6	15.4
Other Fixed Income Securities	14.4	18.8	4.3	16.6
Total Level 2	$ 239.6	$ 88.4	$ 52.5	$ 57.0
Total Marketable Securities	$ 492.3	$ 131.3	$ 57.7	$ 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.

7.

ASSET RETIREMENT OBLIGATIONS

In accordance with accounting guidance for conditional AROs, NU, including CL&P, NSTAR Electric, 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 a corresponding amount 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 Regulatory Assets as of December 31, 2012 and 2011. 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, 2012 and 2011. For further information, see Note 3, "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)	**2012**	**2011**
Balance as of Beginning of Year	$ 56.2	$ 53.3
Liability Assumed Upon Consolidation of CYAPC and YAEC	284.2	-
Liability Assumed Upon Merger With NSTAR	35.9	-
Liabilities Incurred During the Year	1.5	2.1
Liabilities Settled During the Year	(7.2)	(0.8)
Accretion	20.2	3.5
Revisions in Estimated Cash Flows	21.4	(1.9)
Balance as of End of Year	$ 412.2	$ 56.2

As of December 31,

(Millions of Dollars)	2012 CL&P	2012 NSTAR Electric	2012 PSNH	2012 WMECO	2011 CL&P	2011 NSTAR Electric[1]	2011 PSNH	2011 WMECO
Balance as of Beginning of Year	$ 32.2	$ 27.5	$ 17.0	$ 4.0	$ 29.3	$ 26.2	$ 17.6	$ 3.6
Liabilities Incurred During the Year	-	-	0.3	-	1.7	-	0.2	0.2
Liabilities Settled During the Year	(0.9)	(1.0)	-	-	(0.8)	-	-	-
Accretion	2.0	1.5	1.1	0.3	2.0	1.3	1.1	0.2
Revisions in Estimated Cash Flows	0.3	3.4	-	-	-	-	(1.9)	-
Balance as of End of Year	$ 33.6	$ 31.4	$ 18.4	$ 4.3	$ 32.2	$ 27.5	$ 17.0	$ 4.0

(1) NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011.

The Liability Assumed Upon Consolidation of CYAPC and YAEC represents the CYAPC and YAEC ARO fair value as of the merger date. The fair value of the ARO for CYAPC and YAEC includes uncertainties of the fuel off-load dates related to the DOE s timing of performance regarding its obligation to dispose of the spent nuclear fuel and high level waste. The incremental asset recorded as an offset to the ARO was fully depreciated since the plants have no remaining useful life. Any changes in the assumptions used to calculate the fair value of the ARO are recorded as an offset to the related regulatory asset. The assets held in the decommissioning trust are restricted for settling the asset retirement obligation and all other decommissioning obligations. For further information on the regulatory asset established or the assets held in trust to support this obligation, see Note 3, "Regulatory Accounting," and Note 6, "Marketable Securities," to the consolidated financial statements.

8.

SHORT-TERM DEBT

Limits: The amount of short-term borrowings that may be incurred by CL&P, NSTAR Electric and WMECO is subject to periodic approval by the FERC. 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. On March 22, 2012, the FERC approved CL&P's application requesting to increase its total short-term borrowing capacity from a maximum of $450 million to a maximum of $600 million for the authorization period through December 31, 2013. On May 16, 2012, the FERC granted authorization to allow NSTAR Electric to issue total short-term debt securities in an aggregate principal amount not to exceed $655 million outstanding at any one time, effective October 23, 2012 through October 23, 2014. 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.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant plus an additional $60 million until further ordered by the NHPUC. As of December 31, 2012, PSNH's short-term debt authorization under the 10 percent of net fixed plant test plus $60 million totaled approximately $280 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, 2012, CL&P had $482 million of unsecured debt capacity available under this authorization.

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

Credit Agreements and Commercial Paper Programs: On July 25, 2012, NU, CL&P, NSTAR LLC, NSTAR Gas, PSNH, WMECO, and Yankee Gas jointly entered into a five-year $1.15 billion revolving credit facility. The new facility replaced (1) the NSTAR LLC revolving credit facility of $175 million that served to backstop a commercial paper program utilized by NSTAR LLC and was scheduled to expire on December 31, 2012, (2) the NSTAR Gas revolving credit facility of $75 million that expired on June 8, 2012, and (3) the CL&P, PSNH, WMECO, and Yankee Gas joint three-year $400 million and NU parent three-year $500 million unsecured revolving credit facilities that were scheduled to expire on September 24, 2013. The new facility expires on July 25, 2017. Management expects the new facility to be used primarily to backstop the $1.15 billion commercial paper program at NU, which commenced July 25, 2012. The commercial paper program allows NU parent to issue commercial paper as a form of short-term debt. Under the terms of the agreement, NU parent may provide intercompany loans to its subsidiaries, including CL&P, PSNH and WMECO.

On July 25, 2012, NSTAR Electric entered into a five-year $450 million revolving credit facility. This new facility serves to backstop NSTAR Electric s existing $450 million commercial paper program. The new facility expires on July 25, 2017. This new facility replaced a prior $450 million NSTAR Electric revolving credit facility that was scheduled to expire on December 31, 2012.

As of December 31, 2012, NU had $1.15 billion in short-term borrowings outstanding under its commercial paper program. The weighted-average interest rate on these borrowings as of December 31, 2012 was 0.46 percent, which is generally based on money market rates. As of December 31, 2012, there were inter-company loans of $987.5 million from NU to its subsidiaries ($405.1 million for CL&P, $63.3 million for PSNH, and $31.9 million for WMECO). As of December 31, 2012, NSTAR Electric had $276 million in short-term borrowings outstanding under its commercial paper program, leaving $174 million of available borrowing capacity. The weighted-average interest rate on these borrowings as of December 31, 2012 was 0.31 percent, which is generally based on money market rates.

As of December 31, 2011, CL&P and Yankee Gas had $31 million and $30 million, respectively, in short-term borrowings outstanding under the joint $400 million revolving credit facility with weighted average interest rates of 4.03 percent and 2.07 percent, respectively. As of December 31, 2011, NU parent had $256 million in short-term borrowings outstanding under its $500 million revolving credit facility with a weighted average interest rate of 2.20 percent. As of December 31, 2011, there were also $17.9 million, $4 million and $5.4 million in LOCs outstanding under the NU parent credit facility for NU, CL&P and PSNH, respectively. As of December 31, 2011, NSTAR Electric had $141.5 million in short-term borrowings outstanding under its existing commercial paper program with a weighted average interest rate of 0.16 percent.

Under the credit facilities, NU and its subsidiaries must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. NU and its subsidiaries were in compliance with these covenants as of December 31, 2012 and 2011. If NU or its subsidiaries 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 the commercial paper program are included in Notes Payable for NU and NSTAR Electric and classified in current liabilities on the accompanying consolidated balance sheet as management anticipates that all borrowings under these credit facilities will be outstanding for no more than 364 days at one time. Intercompany loans from NU to PSNH and WMECO are included in Notes Payable to Affiliated Companies and classified in current liabilities on the accompanying consolidated balance sheet.

On January 15, 2013, CL&P issued $400 million of Series A First and Refunding Mortgage Bonds with a coupon rate of 2.5 percent and a maturity date of January 15, 2023. The proceeds, net of issuance costs, were used to pay short-term borrowings outstanding under the CL&P credit agreement and the NU commercial paper program. As a result, as of December 31, 2012, CL&P's credit agreement borrowings of $89 million and intercompany loans related to the commercial paper program of $305.8 million have been classified as Long-Term Debt on the accompanying consolidated balance sheet.

CL&P Credit Agreement: On March 26, 2012, CL&P entered into a five-year unsecured revolving credit facility in the amount of $300 million, which expires on March 26, 2017. Under this facility, CL&P can borrow either on a short-term or a long-term basis subject to regulatory approval. As of December 31, 2012, CL&P had $89 million in borrowings outstanding under this credit agreement with a weighted average interest rate of 3.325 percent.

136

Under this facility, CL&P may borrow at prime rates or LIBOR-based rates, plus an applicable margin based on the higher of S&P s or Moody s credit ratings.

In addition, CL&P must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. CL&P was in compliance with these covenants as of December 31, 2012. If CL&P was not in compliance with these covenants, an event of default would occur requiring all outstanding borrowings to be repaid and additional borrowings would not be permitted under this credit facility.

Working Capital: NU, CL&P, NSTAR Electric, PSNH and WMECO use their available capital resources to fund their respective construction expenditures, meet debt requirements, pay costs, including storm-related costs, pay dividends, and fund other corporate obligations, such as pension contributions. The current growth in NU s transmission construction expenditures utilizes a significant amount of cash for projects that have a long-term return on investment and recovery period. In addition, NU s Regulated companies operate in an environment where recovery of its electric and natural gas distribution construction expenditures takes place over an extended period of time. This impacts the timing of the revenue stream designed to fully recover the total investment plus a return on the equity portion of the cost and related financing costs. These factors have resulted in NU s current liabilities exceeding current assets by approximately $1.4 billion, $268 million, $198 million and $60 million at NU, CL&P, NSTAR Electric and WMECO, respectively, as of December 31, 2012.

As of December 31, 2012, approximately $730 million of NU's current liabilities relates to long-term debt that will be paid in the next 12 months, consisting of $550 million for NU parent, $55 million for WMECO, and $125 million for CL&P. Approximately $32 million relates to the amortization of the purchase accounting fair value adjustment that will be amortized in the next twelve months. NU, with its strong credit ratings, has several options available in the financial markets to repay or refinance these maturities with the issuance of new long-term debt. NU, CL&P, NSTAR Electric, and WMECO will reduce their short-term borrowings with cash received from operating cash flows or with the issuance of new long-term debt, as deemed appropriate given capital requirements and maintenance of NU's credit rating and profile. Management expects the future operating cash flows of NU, CL&P, NSTAR Electric and WMECO along with the access to financial markets, will be sufficient to meet any future operating requirements and capital investment forecasted opportunities.

Money Pool: As of December 31, 2011, NU parent, CL&P, PSNH, WMECO, Yankee Gas and certain of NU's other subsidiaries were members of the Money Pool. Short-term borrowing needs of the member companies were met with available funds of other member companies, including funds borrowed by NU parent. Investing and borrowing subsidiaries received or paid interest based on the average daily federal funds rate. In NU's consolidated financial statements, Money Pool amounts payable to or receivable from members eliminated in consolidation. As of December 31, 2011, Money Pool amounts were as follows:

(Millions of Dollars, except percentages)	As of and for the Year Ended December 31, 2011		
	CL&P	**PSNH**	**WMECO**
Borrowings from/(Lendings to)	$ 58.5	$ (55.9)	$ (11.0)
Weighted-Average Interest Rates	0.08 %	0.1 %	0.1 %

The net borrowings from/(lendings to) the Money Pool were 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, NSTAR Electric, PSNH and WMECO are as follows:

CL&P	As of December 31,	
(Millions of Dollars)	**2012**	**2011**
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%-5.95% Fixed Rate Tax Exempt due 2016-2028 (1)	-	116.4
4.375% Fixed Rate Tax Exempt due 2028	120.5	120.5
1.25% Fixed Rate Tax Exempt due 2028(2)	125.0	125.0
1.55% Fixed Rate Tax Exempt due 2031(3)	62.0	62.0
Total Pollution Control Notes	307.5	423.9
Total First Mortgage Bonds and Pollution Control Notes	2,227.3	2,343.7
Fees and Interest due for Spent Nuclear Fuel Disposal Costs	244.3	244.1
CL&P Commercial Paper and Revolver Borrowings(4)	394.8	-
Less Amounts due Within One Year(2)	(125.0)	(62.0)
Unamortized Premiums and Discounts, Net	(3.6)	(4.0)
CL&P Long-Term Debt	$ 2,737.8	$ 2,521.8

NSTAR Electric		**As of December 31,**			
(Millions of Dollars)			**2012**		**2011** [5]
Debentures:					
	4.875% due 2012 [6]	$	-	$	400.0
	4.875% due 2014		300.0		300.0
	2.375% due 2022 [6]		400.0		-
	5.625% due 2017		400.0		400.0
	5.75% due 2036		200.0		200.0
	5.50% due 2040		300.0		300.0
Total Debentures			1,600.0		1,600.0
Bonds:					
	7.375% Tax Exempt Sewage Facility Revenue Bonds, due 2015		8.0		8.7
Less Amounts due Within One Year			(1.7)		(400.7)
Unamortized Premiums and Discounts, Net			(5.4)		(4.7)
NSTAR Electric Long-Term Debt		$	1,600.9	$	1,203.3

PSNH		**As of December 31,**			
(Millions of Dollars)			**2012**		**2011**
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		122.0		122.0
	3.20% 2011 Series R due 2021		160.0		160.0
Total First Mortgage Bonds			712.0		712.0
Pollution Control Revenue Bonds:					
	4.75% - 5.45% Tax Exempt Series B and C due 2021		198.2		198.2
	Adjustable Rate Series A due 2021		89.3		89.3
Total Pollution Control Revenue Bonds			287.5		287.5
Unamortized Premiums and Discounts, Net			(1.6)		(1.8)
PSNH Long-Term Debt		$	997.9	$	997.7

WMECO		**As of December 31,**			
(Millions of Dollars)			**2012**		**2011**
Pollution Control Revenue Bonds and Other Notes:					
	5.85% Tax Exempt PCRBs 1993 Series A, due 2028 [7]	$	-	$	53.8

5.00% Senior Notes Series A, due 2013		55.0		55.0
5.90% Senior Notes Series B, due 2034		50.0		50.0
5.24% Senior Notes Series C, due 2015		50.0		50.0
6.70% Senior Notes Series D, due 2037		40.0		40.0
5.10% Senior Notes Series E, due 2020		95.0		95.0
3.50% Senior Notes Series F, due 2021 [8]		250.0		100.0
Total Pollution Control Revenue Bonds and Other Notes		540.0		443.8
Fees and Interest due for Spent Nuclear Fuel Disposal Costs		57.3		57.3
Less Amounts due Within One Year		(55.0)		-
Unamortized Premiums and Discounts, Net		8.0		(1.6)
WMECO Long-Term Debt	$	550.3	$	499.5

OTHER		**As of December 31,**		
(Millions of Dollars)		**2012**		**2011**
Yankee Gas - First Mortgage Bonds:				
7.19% Series E due 2012	$	-	$	4.3
8.48% Series B due 2022		20.0		20.0
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		345.0		349.3
Less Amounts due Within One Year		-		(4.3)
Unamortized Premium		0.8		0.9
Yankee Gas Long-Term Debt		345.8		345.9
NSTAR Gas - First Mortgage Bonds:				
9.95% Series J due 2020		25.0		N/A
7.11% Series K due 2033		35.0		N/A
7.04% Series M due 2017		25.0		N/A
4.46% Series N due 2020		125.0		N/A
NSTAR Gas Long-Term Debt		210.0		N/A
Other - Notes and Debentures:				
7.25% Senior Notes Series A due 2012 (NU Parent) [9]		-		263.0
5.65% Senior Notes Series C due 2013 (NU Parent)		250.0		250.0
Variable Rate Senior Notes Series D due 2013 (NU Parent) [9]		300.0		-
4.50% Debentures due 2019 (NSTAR LLC)		350.0		N/A
Spent Nuclear Fuel Obligation (CYAPC)		179.3		N/A
Total Other Long-Term Debt		1,079.3		513.0
Fair Value Adjustment [10]		259.9		2.3
Less Amounts due Within One Year		(550.0)		(263.0)
Less: Fair Value Adjustment - Current Portion[10]		(31.7)		(2.3)
Total NU Long-Term Debt	$	7,200.2	$	4,614.9

(1)

On October 1, 2012, CL&P redeemed at par four different series of tax-exempt PCRBs totaling $116.4 million. The PCRBs had maturity dates ranging from 2016 through 2028 and coupon rates of 5.85 percent through 5.95 percent.

(2)

The $125 million of tax-exempt PCRBs were issued with an initial fixed rate term period ending on September 2, 2013, and are subject to mandatory tender for purchase on September 3, 2013, at which time CL&P expects to remarket the PCRBs.

(3)

On April 2, 2012, CL&P remarketed $62 million of tax-exempt PCRBs for a three-year period. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.55 percent during the current three-year fixed rate period and are subject to mandatory tender for purchase on April 1, 2015.

(4)

On January 15, 2013, CL&P issued $400 million of 2.5 percent Series A First and Refunding Mortgage Bonds with a maturity date of January 15, 2023. The proceeds, net of issuance expenses, were used to repay the amounts outstanding under the CL&P revolver and the NU commercial paper program. As a result, these amounts have been classified as Long-Term Debt as of December 31, 2012.

(5)

NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011.

(6)

On October 15, 2012, NSTAR Electric issued at a discount $400 million of 2.375 percent Debentures at a yield of 2.406 percent that will mature on October 15, 2022. The proceeds, net of issuance costs, were used to pay $400 million of 4.875 percent Debentures that matured on October 15, 2012.

(7)

On October 1, 2012, WMECO redeemed at par $53.8 million of tax-exempt PCRBs. The PCRBs had a maturity date of 2028 and a coupon of 5.85 percent.

(8)

On October 4, 2012, WMECO issued at a premium $150 million of senior unsecured notes at a yield of 2.673 percent that will mature on September 15, 2021. The senior notes are part of the same series of WMECO s existing 3.5 percent coupon Series F Senior Notes that were initially issued in September 2011. As a result, the aggregate principal amount of WMECO s outstanding Series F Senior Notes totaled $250 million.

(9)

On March 22, 2012, NU parent issued $300 million of floating rate Series D Senior Notes with a maturity date of September 20, 2013. The notes have a coupon rate based on the three-month LIBOR rate plus a credit spread of 0.75 percent and will reset quarterly. The notes had an interest rate of 1.059 percent as of December 31, 2012. The proceeds, net of issuance expenses, were used to repay at maturity the NU parent $263 million Series A Senior Notes that matured on April 1, 2012, to repay short-term borrowings outstanding under the NU parent Credit Agreement and for other general corporate purposes.

(10)

As of December 31, 2012, amount relates to the purchase price adjustment required to record the NSTAR long-term debt issuances at fair value on the date of the merger. As of December 31, 2011, amount related to a fixed to floating interest rate swap on the $263 million NU parent note that matured on April 1, 2012. The change in fair value of the interest component of the debt was recorded as an adjustment to Current Portion - Long Term Debt as of December 31, 2011 with an equal and offsetting adjustment to Current Derivative Assets.

Long-term debt maturities and cash sinking fund requirements on debt outstanding as of December 31, 2012 for the years 2013 through 2017 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, 2012:

(Millions of Dollars)	**NU**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**
2013	$ 731.7	$ 125.0	$ 1.7	$ -	$ 55.0
2014	576.6	150.0	301.7	50.0	-
2015	216.7	162.0	4.7	-	50.0
2016	-	-	-	-	-
2017	745.0	250.0	400.0	70.0	-
Thereafter	4,559.8	1,540.3	899.9	879.5	435.0
Total	$ 6,829.8	$ 2,227.3	$ 1,608.0	$ 999.5	$ 540.0

The utility plant of CL&P, PSNH, Yankee Gas and NSTAR Gas is subject to the lien of each company's respective first mortgage bond indenture. NSTAR Electric, WMECO, NU Parent and NSTAR LLC debt is unsecured.

The PSNH Series A and Series C tax-exempt bonds are currently callable at 100 percent and 101 percent of par, respectively. The PSNH Series B tax-exempt bond will become callable in June 2013. CL&P s $125 million and $62 million tax-exempt PCRBs, which are subject to mandatory tender for purchase on September 3, 2013 and April 1, 2015, respectively, cannot be redeemed prior to their respective tender dates. CL&P s $120.5 million tax-exempt PCRBs will be subject to redemption at par on or after September 1, 2021. All other long-term debt securities are subject to make-whole provisions.

As of December 31, 2012, CL&P had $307.5 million of tax-exempt PCRBs outstanding. CL&P s obligation to repay each series of PCRBs is secured by first mortgage bonds. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. If CL&P failed to meet its obligations under the PCRBs, then these first mortgage bonds would become outstanding.

As of December 31, 2012, 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. PSNH 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 0.20 percent in 2012 and 0.21 percent in 2011.

NU's, including CL&P, NSTAR Electric, PSNH and WMECO, long-term debt agreements provide that NU and certain of its subsidiaries must comply with certain covenants as are customarily included in such agreements, including a minimum equity requirement for NSTAR Gas. Under the minimum equity requirement, the outstanding long-term debt of NSTAR Gas must not exceed equity. NU and these subsidiaries were in compliance with these covenants as of December 31, 2012 and 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 other debt issuances contain cross-default provisions as of December 31, 2012.

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. In addition, as a result of consolidating CYAPC, NU has consolidated $179.3 million in additional spent nuclear fuel obligations, including interest, as of December 31, 2012. Fees due to the DOE for the disposal of CL&P's and WMECO's Prior Period Spent Nuclear Fuel and CYAPC's and YAEC's spent nuclear fuel obligation include accumulated interest costs of $350 million and $219.3 million for NU ($177.8 million and $177.6 million for CL&P and $41.7 million and $41.7 million for WMECO) as of December 31, 2012 and 2011, respectively.

For further information, see Note 1B, "Summary of Significant Accounting Policies Basis of Presentation," to the consolidated financial statements.

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. CYAPC also maintain trusts to fund amounts due to the DOE for the disposal of spent nuclear fuel. For further information on these trusts, see Note 6, "Marketable Securities," to the consolidated financial statements.

10.

EMPLOYEE BENEFITS

A.

Pension Benefits and Postretirement Benefits Other Than Pensions

NUSCO sponsors a defined benefit retirement plan that covers most employees, including CL&P, PSNH, and WMECO employees, hired before 2006 (or as negotiated, for bargaining unit employees), referred to as the NUSCO Pension Plan. NSTAR Electric serves as plan sponsor for a defined benefit retirement plan that covers most employees of NSTAR Electric & Gas, hired before October 1, 2012, or as negotiated by bargaining unit employees, referred to as the NSTAR Pension Plan. Both plans are subject to the provisions of ERISA, as amended by the PPA of 2006. NUSCO and NSTAR Electric & Gas each maintain SERPs and other non-qualified defined benefit retirement plans (herein collectively referred to as the SERP Plans), which provide benefits in excess of Internal Revenue Code limitations to eligible current and retired participants that would have otherwise been provided under the Pension Plans.

NUSCO and NSTAR Electric & Gas also sponsor defined benefit postretirement plans that provide certain retiree health care benefits, primarily medical and dental, and life insurance benefits to retiring employees that meet certain age and service eligibility requirements (NUSCO PBOP Plans and NSTAR PBOP Plan, respectively). Under certain circumstances, eligible retirees are required to contribute to the costs of postretirement benefits. The benefits provided under the NUSCO and NSTAR PBOP Plans are not vested and the Company has the right to modify any benefit provision subject to applicable laws at that time.

The funded status of the Pension, SERP and PBOP Plans is calculated based on the difference between the benefit obligation and the fair value of plan assets. The funded status of the Pension, SERP and PBOP Plans is recorded on the consolidated balance sheets as a liability with an offset to Accumulated Other Comprehensive Income/(Loss). Pension, SERP and PBOP costs for the Regulated companies are recorded as Regulatory Assets as these amounts are recovered from customers. Regulatory accounting was also applied to the portions of the NUSCO and NSTAR Electric & Gas costs that support the Regulated companies, as these costs are also recovered from customers. Pension and PBOP costs for the unregulated companies are recorded on an after-tax basis to Accumulated Other Comprehensive Income/(Loss). For further information, see Note 3, "Regulatory Accounting," and Note 15, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements. The SERP Plans do not have plan assets.

For the NUSCO Pension and PBOP Plans, 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. Investment gains or losses for this purpose are the difference between the calculated expected return and the actual return. 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. For the NSTAR Pension and PBOP Plans, the entire difference between the actual return and calculated expected return on plan assets is reflected as a component of unrecognized actuarial gain or loss. Unrecognized actuarial gains or losses are amortized as a component of Pension and PBOP expense over the estimated average future employee service period.

Pension and SERP Plans: The funded status of each of the plans is recorded on the respective sponsor's balance sheet: NUSCO (NUSCO Pension and NUSCO SERP), NSTAR Electric (NSTAR Pension) and NSTAR Electric & Gas (NSTAR SERP). The NUSCO plans are accounted for under the multiple-employer approach while the NSTAR plans are accounted for under the multi-employer approach. Accordingly, the balance sheet of NSTAR Electric reflects the full funded status of the NSTAR Pension Plan.

The following tables provide information on the Pension and SERP Plan benefit obligations, fair values of Pension Plan assets, and funded status:

NU *(Millions of Dollars)*	Pension and SERP As of December 31, **2012**	**2011**
Change in Benefit Obligation		
Benefit Obligation as of Beginning of Year	$ (3,098.9)	$ (2,820.9)
Liabilities Assumed from Merger with NSTAR	(1,409.7)	-
Service Cost	(84.3)	(55.4)
Interest Cost	(198.3)	(153.3)
Actuarial Loss	(429.7)	(206.1)
Benefits Paid - Excluding Lump Sum Payments	187.7	134.4
Benefits Paid SERP	4.2	2.4
SERP curtailment	6.2	-
Benefit Obligation as of End of Year	$ (5,022.8)	$ (3,098.9)
Change in Pension Plan Assets		
Fair Value of Plan Assets as of Beginning of Year	$ 2,005.9	$ 1,977.6
Assets Assumed from Merger with NSTAR	984.7	-
Employer Contributions	222.4	143.6
Actual Return on Plan Assets	386.0	19.1
Benefits Paid - Excluding Lump Sum Payments	(187.7)	(134.4)
Fair Value of Plan Assets as of End of Year	$ 3,411.3	$ 2,005.9
Funded Status as of December 31st	$ (1,611.5)	$ (1,093.0)

	Pension and SERP							
	As of December 31, 2012				As of December 31, 2011			
(Millions of Dollars)	**CL&P**	**NSTAR Electric (1)**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric (1),(2)**	**PSNH**	**WMECO**
Change in Benefit Obligation								
Benefit Obligation as of Beginning of Year	$ (1,043.8)	$ (1,346.2)	$ (497.9)	$ (215.8)	$ (964.3)	$ (1,184.6)	$ (448.7)	$ (196.6)
Service Cost	(21.8)	(30.3)	(11.8)	(4.1)	(19.5)	(26.0)	(10.6)	(3.9)
Interest Cost	(51.2)	(58.9)	(24.4)	(10.5)	(51.9)	(61.0)	(24.4)	(10.7)
Actuarial Loss	(117.4)	(63.6)	(61.3)	(24.0)	(64.0)	(138.0)	(33.2)	(15.4)
Benefits Paid - Excluding	55.9	69.0	19.7	11.3	55.6	59.6	18.9	10.8

Lump Sum Payments																
Benefits Paid - SERP		0.3		-		-		-		0.3		-		0.1		-
Curtailment and Settlement Payments		-		-		(0.3)		-		-		3.8		-		-
Benefit Obligation as of End of Year	$	(1,178.0)	$	(1,430.0)	$	(576.0)	$	(243.1)	$	(1,043.8)	$	(1,346.2)	$	(497.9)	$	(215.8)
Change in Pension Plan Assets																
Fair Value of Plan Assets as of Beginning of Year	$	869.6	$	988.5	$	279.7	$	202.0	$	918.4	$	930.6	$	185.4	$	209.8
Employer Contributions		-		25.0		87.7		-		-		125.0		112.6		-
Actual Return/(Loss) on Plan Assets		123.9		124.6		38.9		27.8		6.8		(3.7)		0.6		3.0
Benefits Paid - Excluding Lump Sum Payments		(55.9)		(69.0)		(19.7)		(11.3)		(55.6)		(59.6)		(18.9)		(10.8)
Benefits Paid - Settlement Payments		-		-		-		-		-		(3.8)		-		-
Fair Value of Plan Assets as of End of Year	$	937.6	$	1,069.1	$	386.6	$	218.5	$	869.6	$	988.5	$	279.7	$	202.0
Funded Status as of December 31st	$	(240.4)	$	(360.9)	$	(189.4)	$	(24.6)	$	(174.2)	$	(357.7)	$	(218.2)	$	(13.8)

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.

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 informally support the SERP liability, see Note 6, "Marketable Securities," to the consolidated financial statements.

(1) NSTAR Electric amounts do not include benefit obligations of the NSTAR SERP Plan.
(2) NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011.

The accumulated benefit obligation for the Pension and SERP Plans is as follows:

	Pension and SERP As of December 31,	
(Millions of Dollars)	**2012**	**2011**
NU	$ 4,622.1	$ 2,810.6
CL&P	1,061.8	938.4
NSTAR Electric [(1)]	1,353.1	1,271.3
PSNH	515.9	444.8
WMECO	221.3	195.5

(1) NSTAR Electric amounts are not included in NU consolidated as of December 31, 2011 and do not include the accumulated benefit obligation for the SERP Plan.

The following actuarial assumptions were used in calculating the Pension and SERP Plans' year end funded status:

	Pension and SERP As of December 31,	
	2012	**2011**
NUSCO Pension and SERP Plans		
Discount Rate	4.24 %	5.03 %
Compensation/Progression Rate	3.50 %	3.50 %
NSTAR Pension and SERP Plans		
Discount Rate	4.13 %	4.52 %
Compensation/Progression Rate	4.00 %	4.00 %

Pension and SERP Expense: For the NUSCO Plans, 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 for each subsidiary. The actual investment return in the trust each year is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. For the NSTAR Pension Plan, the net periodic pension expense recorded at NSTAR Electric represents the full cost of the plan and then a portion of the costs are allocated to affiliated companies based on participant demographic data. The components of net periodic benefit expense, 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 SERP Plans were as follows:

	Pension and SERP For the Year Ended December 31, 2012				
(Millions of Dollars)	**NU**	**CL&P**	**NSTAR Electric** (1)	**PSNH**	**WMECO**
Service Cost	$ 84.3	$ 21.8	$ 30.3	$ 11.8	$ 4.1
Interest Cost	198.3	51.2	58.9	24.4	10.5
Expected Return on Plan Assets	(220.9)	(70.6)	(65.6)	(28.2)	(16.4)
Actuarial Loss	172.4	49.6	63.1	16.2	10.7
Prior Service Cost/(Credit)	7.9	3.6	(0.6)	1.5	0.8
Total Net Periodic Benefit Expense	$ 242.0	$ 55.6	$ 86.1	$ 25.7	$ 9.7
Curtailments and Settlements	$ 2.2	$ -	$ -	$ -	$ -
Related Intercompany Allocations	N/A	$ 42.8	$ (12.3)	$ 10.1	$ 8.1
	$ 70.6	$ 26.8	$ 30.7	$ 7.9	$ 5.1

Capitalized Pension Expense

	Pension and SERP For the Year Ended December 31, 2011				
(Millions of Dollars)	**NU**	**CL&P**	**NSTAR Electric (1)**	**PSNH**	**WMECO**
Service Cost	$ 55.4	$ 19.5	$ 26.0	$ 10.6	$ 3.9
Interest Cost	153.3	51.9	61.0	24.4	10.7
Expected Return on Plan Assets	(170.8)	(76.6)	(71.4)	(19.8)	(17.7)
Actuarial Loss	84.2	33.4	48.6	10.7	7.1
Prior Service Cost/(Credit)	9.7	4.2	(0.7)	1.8	0.9
Total Net Periodic Benefit Expense	$ 131.8	$ 32.4	$ 63.5	$ 27.7	$ 4.9
Related Intercompany Allocations	N/A	$ 34.1	$ (10.2)	$ 7.6	$ 6.2
Capitalized Pension Expense	$ 29.7	$ 16.6	$ 19.8	$ 7.6	$ 2.7

	Pension and SERP For the Year Ended December 31, 2010				
(Millions of Dollars)	**NU**	**CL&P**	**NSTAR Electric (1)**	**PSNH**	**WMECO**
Service Cost	$ 51.0	$ 17.6	$ 23.6	$ 10.0	$ 3.5
Interest Cost	152.6	52.2	61.8	24.1	10.7
Expected Return on Plan Assets	(182.6)	(85.8)	(62.8)	(14.7)	(19.5)
Actuarial Loss	53.5	20.7	50.4	7.2	4.3
Prior Service Cost/(Credit)	9.9	4.2	(0.7)	1.8	0.9
Total Net Periodic Benefit Expense/(Income)	$ 84.4	$ 8.9	$ 72.3	$ 28.4	$ (0.1)
Related Intercompany Allocations	N/A	$ 25.2	$ (11.6)	$ 6.0	$ 4.5
Capitalized Pension Expense	$ 16.9	$ 3.8	$ 24.5	$ 6.9	$ -

(1) NSTAR Electric amounts are included in NU consolidated from the date of the merger, April 10, 2012, through December 31, 2012. NSTAR Electric amounts are not included in NU consolidated for the years ended December 31, 2011 and 2010. NSTAR Electric's allocated expense associated with the NSTAR SERP was $3.6 million, $4.4 million and $3.9 million for the years ended December 31, 2012, 2011 and 2010, respectively, and are not included in the NSTAR Electric amounts in the tables above.

The following actuarial assumptions were used to calculate Pension and SERP expense amounts:

	Pension and SERP For the Years Ended December 31,		
NUSCO Pension and SERP Plans	**2012**	**2011**	**2010**
Discount Rate	5.03 %	5.57 %	5.98 %
Expected Long-Term Rate of Return	8.25 %	8.25 %	8.75 %
Compensation/Progression Rate	3.50 %	3.50 %	4.00 %
NSTAR Pension and SERP Plans			
Discount Rate	4.52 %	5.30 %	5.85 %
Expected Long-Term Rate of Return	7.30 %	8.00 %	8.00 %
Compensation/Progression Rate	4.00 %	4.00 %	4.00 %

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 during the years presented:

	Amounts Reclassified To/From			
	Regulatory Assets		OCI	
(Millions of Dollars)	For the Years Ended December 31,			
NU Pension and SERP Plans (1)	**2012**	**2011**	**2012**	**2011**
Actuarial Losses Arising During the Year	$ 245.7	$ 334.8	$ 19.1	$ 23.0
Actuarial Losses Reclassified as Net Periodic Benefit Expense	(164.6)	(79.4)	(7.8)	(4.8)
Prior Service Cost Reclassified as Net Periodic Benefit Expense	(7.7)	(9.4)	(0.2)	(0.3)

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, 2012 and 2011, and the amounts that are expected to be recognized as components in 2013:

(Millions of Dollars)	Regulatory Assets as of December 31,		Expected 2013	AOCI as of December 31,		Expected 2013
NU Pension and SERP Plans (1)	**2012**	**2011**	**Expense**	**2012**	**2011**	**Expense**
Actuarial Loss	$ 1,973.8	$ 1,126.1	$ 200.8	$ 81.5	$ 70.2	$ 9.3

Prior Service Cost	21.2	29.3	3.9	1.2	1.4	0.2

(1)

The NU consolidated amounts reflect the NSTAR Pension and SERP Plans from the date of the merger, April 10, 2012, through December 31, 2012.

NSTAR Electric continues to maintain reporting requirements as an SEC registrant. Included in the amounts above as of December 31, 2012 are $724 million of unrecognized actuarial losses included in Regulatory Assets for NSTAR Electric. For the year ended December 31, 2012, NSTAR Electric reclassified $62.8 million of actuarial losses and $0.6 million of prior service credit as net periodic benefit expense and $4.6 million of actuarial losses arose during the year. As of December 31, 2011, NSTAR Electric had $782.3 million of unrecognized actuarial losses and $0.6 million of prior service credit included in Regulatory Assets. For the year ended December 31, 2011, NSTAR Electric reclassified $48.4 million of actuarial losses and $0.7 million of prior service credit as net periodic benefit expense and $212 million of actuarial losses arose during the year.

PBOP Plans: The NUSCO Plans are accounted for under the multiple-employer basis while the NSTAR Plan is accounted for under the multi-employer basis. Accordingly, the funded status of the NUSCO PBOP Plans is allocated to its subsidiaries, including CL&P, PSNH and WMECO, while the NSTAR PBOP Plan is not reflected on the SEC registrant NSTAR Electric s balance sheet.

NU annually funds postretirement costs through tax deductible contributions to external trusts.

The following tables represent information on PBOP Plan benefit obligations, fair values of plan assets, and funded status:

	PBOP As of December 31,															
	2012								2011							
(Millions of Dollars)		**NU [1]**		**CL&P**		**PSNH**		**WMECO**		**NU**		**CL&P**		**PSNH**		**WMECO**
Change in Benefit Obligation																
Benefit Obligation as of Beginning of Year	$	(520.9)	$	(198.9)	$	(99.2)	$	(42.9)	$	(489.9)	$	(190.2)	$	(89.9)	$	(41.7)
Liabilities Assumed from Merger with NSTAR		(770.6)		-		-		-		-		-		-		-
Service Cost		(15.7)		(3.0)		(2.0)		(0.6)		(9.2)		(2.9)		(1.9)		(0.6)
Interest Cost		(49.0)		(9.2)		(4.6)		(2.0)		(25.7)		(10.0)		(4.8)		(2.2)
Actuarial Gain/(Loss)		70.9		1.2		0.3		0.1		(30.1)		(8.5)		(8.4)		(1.0)
Federal Subsidy on Benefits Paid		(6.2)		(1.7)		(0.6)		(0.3)		(4.1)		(1.8)		(0.7)		(0.4)
Benefits Paid		58.2		14.8		5.9		3.2		38.1		14.5		6.5		3.0
Benefit Obligation as of End of Year	$	(1,233.3)	$	(196.8)	$	(100.2)	$	(42.5)	$	(520.9)	$	(198.9)	$	(99.2)	$	(42.9)
Change in Plan Assets																