CONNECTICUT LIGHT & POWER CO
Form 10-K
February 25, 2014

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, 2013
	OR
[ ]	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the transition period from ____________ to ____________

Commission File Number	**Registrant; State of Incorporation; Address; and Telephone Number**	**I.R.S. Employer Identification No.**
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-02301		04-1278810

	NSTAR ELECTRIC COMPANY (a Massachusetts corporation) 800 Boylston Street Boston, Massachusetts 02199 Telephone: (617) 424-2000	
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. [ ]

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, 2013) was $13,224,337,788 based on a closing sales price of $42.02 per share for the 314,715,321 common shares outstanding on June 30, 2013.

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
	315,434,940 shares

Northeast Utilities Common shares, $5.00 par value	
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 Yankee Energy System, Inc.
HWP	HWP Company, formerly the Holyoke Water Power Company
MYAPC	Maine Yankee Atomic Power Company
NGS	Northeast Generation Services Company
NPT	Northern Pass Transmission LLC
NSTAR	Parent Company of NSTAR Electric, NSTAR Gas and other subsidiaries (prior to the merger with NU)
NSTAR Electric	NSTAR Electric Company
NSTAR Gas	NSTAR Gas Company
NU Enterprises	NU Enterprises, Inc., the parent company of NGS, Select Energy, Select Energy Contracting, Inc., E.S. Boulos Company and NSTAR Communications, Inc.
NU or the Company	Northeast Utilities and subsidiaries
NU parent and other companies	NU parent and other companies is comprised of NU parent, NUSCO and other subsidiaries, which primarily include NU Enterprises, 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:	
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
FERC ALJ	FERC Administrative Law Judge
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 supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
NU 2012 Form 10-K	The Northeast Utilities and Subsidiaries 2012 combined 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
Settlement Agreements	The comprehensive settlement agreements reached by NU and NSTAR with the Massachusetts Attorney General and the DOER on February 15, 2012 related to the merger of NU and NSTAR (Massachusetts settlement agreements) and the comprehensive settlement agreement reached by NU and NSTAR with both the Connecticut Attorney General and the Connecticut Office of Consumer Counsel on March 13, 2012 related to the merger of NU and NSTAR (Connecticut settlement agreement).
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
NSTAR ELECTRIC COMPANY AND SUBSIDIARY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
WESTERN MASSACHUSETTS ELECTRIC COMPANY

2013 FORM 10-K ANNUAL REPORT

TABLE OF CONTENTS

NORTHEAST UTILITIES AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY

NSTAR ELECTRIC COMPANY AND SUBSIDIARY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

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

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

.

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

.

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

.

actions or inaction of 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,

.

fluctuations in weather patterns,

.

changes in laws, regulations or regulatory policy,

.

changes in levels or 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

NSTAR ELECTRIC COMPANY AND SUBSIDIARY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

PART I

Item 1.

Business

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

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 subsidiary, NU Enterprises, which is included in its Parent and other companies results of operations.

NU, CL&P, NSTAR Electric, PSNH and WMECO each report their financial results separately. We also include information in this report on a segment basis for NU. NU recognizes three reportable segments, which are electric distribution, electric transmission and natural gas distribution. NU s electric distribution segment includes the generation businesses of PSNH and WMECO. These three segments represented substantially all of NU's total consolidated revenues for the years ended December 31, 2013 and 2012. CL&P, NSTAR Electric, PSNH and WMECO do not report separate business segments.

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 and its subsidiaries became wholly-owned subsidiaries of NU. NU s consolidated financial statements include the results of operations of NSTAR and its subsidiaries (NSTAR) 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 2013 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers:

(Thousands of Dollars, except percentages)		**2013**	**% of Total**
Residential	$	3,073,181	52
Commercial[1]		2,387,535	31
Industrial		339,917	16
Other and Eliminations		56,547	1
Total Retail Electric Revenues	$	5,857,180	100%

[1] Commercial retail electric revenue includes Streetlighting and Railroad retail revenue.

A summary of our distribution companies retail electric GWh sales and percentage changes for 2013, as compared to 2012, is as follows:

	2013	**2012[1]**	**Percentage Change**
Residential	21,896	21,374	2.4 %
Commercial [2]	27,787	27,647	0.5 %
Industrial	5,648	5,787	(2.4)%
Total	55,331	54,808	1.0 %

[1]

Results include retail electric sales of NSTAR Electric for all of 2012 for comparative purposes only.

[2]

Commercial retail electric GWh sales include Streetlighting and Railroad retail sales.

Our 2013 consolidated retail electric sales were higher, as compared to 2012, due primarily to colder weather in the first and fourth quarters of 2013. The 2013 retail electric sales for CL&P, NSTAR Electric and PSNH increased while they remained unchanged for WMECO, as compared to 2012, due primarily to colder weather in the first and fourth quarters of 2013. In 2013, heating degree days were 17 percent higher in Connecticut and western Massachusetts, 16 percent higher in the Boston metropolitan area, and 15 percent higher in New Hampshire, and cooling degree days were 7 percent lower in Connecticut and western Massachusetts, 2 percent higher in the Boston metropolitan area, and 9 percent lower in New Hampshire, as compared to 2012. On a weather-normalized basis (based on 30-year average temperatures), 2013 retail electric sales for CL&P and PSNH increased, while they decreased for NSTAR Electric and WMECO, as compared to 2012. The 2013 weather-normalized NU consolidated total retail electric sales remained relatively unchanged, as compared to 2012.

For WMECO, fluctuations in retail electric sales do not impact earnings due to the DPU-approved revenue decoupling mechanism. Under this decoupling mechanism, WMECO has an overall fixed annual level of distribution delivery service revenues of $132.4 million, comprised of customer base rate revenues of $125.4 million and a baseline low income discount recovery of $7 million. These two mechanisms effectively break the relationship between sales volume and revenues recognized.

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, 2013, 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 2013 electric franchise retail revenues based on categories of customers:

		CL&P	
(Thousands of Dollars, except percentages)		**2013**	**% of Total**
Residential	$	1,294,160	58
Commercial[1]		780,585	35
Industrial		129,557	6
Other		18,671	1
Total Retail Electric Revenues	$	2,222,973	100%

[1] Commercial retail electric revenue includes Streetlighting and Railroad retail revenue.

A summary of CL&P s retail electric GWh sales and percentage changes for 2013, as compared to 2012, is as follows:

	2013	2012	Percentage Change
Residential	10,314	9,978	3.4 %
Commercial[1]	9,770	9,705	0.7 %
Industrial	2,320	2,426	(4.4)%
Total	22,404	22,109	1.3 %

(1) Commercial retail electric GWh sales include Streetlighting and Railroad retail sales.

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 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 56 percent of its customer load at SS or LRS rates while the other 44 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 rates established by the PURA for CL&P are comprised of the following:

.

An electric generation services charge, 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. This charge is adjusted periodically and reconciled semi-annually in accordance with the directives of PURA.

.

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 to maintain such infrastructure.

.

A federally-mandated congestion charge, or FMCC, 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, and any costs approved by PURA to reduce these charges. This charge also recovers costs associated with CL&P s system resiliency program. This charge is adjusted periodically and reconciled semi-annually in accordance with the directives of PURA.

.

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

.

A competitive transition charge, assessed to recover stranded costs associated with electric industry restructuring such as various IPP contracts. This charge is reconciled annually to actual costs incurred and reviewed by PURA, with any difference refunded to, or recovered from, customers.

.

A system benefits charge established to fund expenses 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; and unfunded storage and disposal costs for spent nuclear fuel generated before 1983. This charge is reconciled annually to actual costs incurred and reviewed by PURA, with any difference refunded to, or recovered from, customers.

.

A 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. The Renewable Energy Investment Fund charge is set by statute and is currently 0.1 cent per kWh.

.

A conservation charge, comprised of a statutory rate established to implement cost-effective energy conservation programs and market transformation initiatives, plus a conservation adjustment mechanism charge to recover the residual energy efficiency spending associated with the expanded energy efficiency costs directed by the Comprehensive Energy Strategy Plan for Connecticut.

Expense/revenue reconciliation amounts for the electric generation services charge and the FMCC are recovered in subsequent rates.

CL&P, jointly with UI, has entered into four CfDs for a total of approximately 787 MW of capacity consisting of three electric generation units 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 generation units 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 through the FMCC charge. The amounts of these payments are subject to changes in capacity and forward reserve prices that the projects receive in the ISO-NE capacity markets.

In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by the PURA (Peaker CfDs). These units have a total of approximately 500 MW of peaking capacity. As directed by the PURA, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant 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 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.

On September 19, 2013, CL&P, along with another Connecticut utility, signed long-term commitments, as required by regulation, to purchase approximately 250 MW of wind power from a Maine wind farm and 20 MW of solar power from sites in Connecticut, at a combined average price of less than $0.08 per kWh. On October 23, 2013, PURA issued a final decision accepting the contracts. The two projects are expected to be operational by the end of 2016.

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 one year 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 wholesale suppliers for firm requirements service for 70 percent of its SS loads for the first half of 2014, and has energy contracts in place to self-supply the remaining 30 percent for the first half of 2014. For the second half of 2014, CL&P has 50 percent of its SS load under contract with various wholesale suppliers for firm requirements service and energy contracts in place to self-supply 10 percent. CL&P intends to purchase 20 to 30 percent of the SS load for the second half of 2014 from wholesale suppliers for firm requirements service and will self-supply the remainder needed. None of the SS load for 2015 has been procured. CL&P has contracts in place for its LRS loads through the second quarter of 2014, and CL&P intends to purchase 100 percent of the LRS load for the third and fourth quarter of 2014 from wholesale suppliers for firm requirements service.

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, 2013, NSTAR Electric furnished retail franchise electric service to approximately 1.2 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 third party 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. On September 4, 2013, the DPU approved WMECO's proposal to build a third solar generation facility and expand its solar energy portfolio from 6 MW to 8 MW. On October 22, 2013, WMECO announced it would install a 3.9 MW solar generation facility on a site in East Springfield, Massachusetts. The facility is expected to be completed in mid-2014 with an estimated cost of approximately $15 million. 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 enter into long-term contracts for 10 megawatts of solar power in connection with the Department of Energy Resources settlement agreement that approved the Merger in Massachusetts. NSTAR Electric has entered in two contracts for 5 MW of capacity,

5

which were approved by the DPU in May, 2013. However these contracts were terminated on November 6, 2013 by mutual agreement of the parties. NSTAR Electric expects to meet its merger commitment by issuing a request for proposals to enter into long-term contracts for additional renewable solar generation.

The following table shows the sources of the 2013 electric franchise retail revenues of NSTAR Electric and WMECO based on categories of customers:

	NSTAR Electric			WMECO		
(Thousands of Dollars, except percentages)		**2013**	**% of Total**		**2013**	**% of Total**
Residential	$	1,066,673	45	$	228,632	57
Commercial[(1)]		1,181,678	25		131,763	33
Industrial		98,130	29		41,218	10
Other		17,092	1		(882)	-
Total Retail Electric Revenues	$	2,363,573	100%	$	400,731	100%

(1) Commercial retail electric revenue includes Streetlighting and Railroad retail revenue.

A summary of NSTAR Electric s and WMECO s retail electric GWh sales and percentage changes for 2013, as compared to 2012, is as follows:

	NSTAR Electric			WMECO		
	2013	**2012**	**Percentage Change**	**2013**	**2012**	**Percentage Change**
Residential	6,831	6,741	1.3 %	1,544	1,517	1.7 %
Commercial[(1)]	13,163	13,115	0.4 %	1,496	1,503	(0.4)%
Industrial	1,312	1,353	(3.0)%	643	663	(3.0)%
Total	21,306	21,209	0.5 %	3,683	3,683	- %

(1) Commercial retail electric GWh sales include Streetlighting and Railroad retail sales.

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 and construction and operation of 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 46 percent of its customer load at basic service rates while the other 54 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 rates established by the DPU for NSTAR Electric and WMECO are comprised of the following:

.

A basic service charge that represents the collection of energy costs, including costs related to charge-offs of uncollected energy costs. 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). Additionally, the DPU has authorized NSTAR Electric to recover the cost of its Dynamic Pricing Smart Grid Pilot Program through the basic service charge. Basic service costs are reconciled annually.

.

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.

.

For WMECO, a revenue decoupling adjustment, that reconciles distribution revenue, on an annual basis, to the amount of distribution revenue approved by the DPU in its last rate case.

.

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

.

A transition charge that 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.

.

Reconciling adjustment charges that recover certain DPU-approved costs, including a pension and PBOP rate to recover incremental pension and PBOP benefit costs, a residential assistance adjustment factor to recover the cost of low income discounts, a net-metering surcharge to collect the lost revenue and credits associated with net-metering facilities installed by customers, a storm recovery charge to collect certain storm related costs, and an energy efficiency reconciliation factor to recover energy efficiency program costs and lost base revenues in addition to those charges recovered in the energy efficiency charge. In addition to these adjustments, NSTAR Electric has a reconciling adjustment charge that collects certain safety and reliability program costs and costs related to its Smart Grid pilot program, while WMECO has a reconciling adjustment charge that recovers costs associated with certain solar projects owned and operated by WMECO.

.

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

.

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

Rate Settlement Agreement

On February 15, 2012, NU and NSTAR reached comprehensive settlement agreements with the Massachusetts Attorney General (Attorney General s settlement agreement) and the DOER related to the merger. The Attorney General s 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. 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 energy policies.

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. WMECO is currently decoupled and NSTAR Electric will propose decoupling in its 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.

NSTAR Electric and WMECO are each subject to service quality (SQ) metrics that measure safety, reliability and customer service and could be required to pay to customers a SQ charge of up to 2.5 percent of annual transmission and distribution revenues for failing to meet such metrics. Neither NSTAR Electric nor WMECO will be required to pay a SQ charge for its 2013 performance as each company achieved results at or above target for all of its respective SQ metrics in 2013.

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, 2013, 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. PSNH completed remaining project construction activities in 2012 and the final cost of the project was approximately $421 million**.**

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.

Prudent Scrubber costs are allowed to be recovered through PSNH's ES rates under New Hampshire law. In November 2011, the NHPUC opened a docket to review the Clean Air Project. For information about this docket, see "Regulatory Developments and Rate Matters New Hampshire Clean Air Project Prudence Proceeding" in the accompanying *Management s Discussion and Analysis*.

The following table shows the sources of PSNH s 2013 electric franchise retail revenues based on categories of customers:

		PSNH	
(Thousands of Dollars, except percentages)		**2013**	**% of Total**
Residential	$	483,716	56
Commercial [1]		293,509	34
Industrial		71,012	8
Other		21,665	2
Total Retail Electric Revenues	$	869,902	100%

[1] Commercial retail electric revenue includes Streetlighting and Railroad retail revenue.

A summary of PSNH s retail electric GWh sales and percentage changes for 2013, as compared to 2012, is as follows:

	2013	**2012**	**Percentage Change**
Residential	3,208	3,138	2.2%
Commercial [1]	3,357	3,338	0.6%
Industrial	1,373	1,345	2.1%
Total	7,938	7,821	1.5%

[1] Commercial retail electric GWh sales include Streetlighting and Railroad retail sales.

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 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 2013, approximately 25 percent of all of PSNH s customers (approximately 54 percent of load) had switched to competitive energy suppliers. This was an increase from 2012, when 9 percent of customers (approximately 44 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 have not chosen a third party supplier, predominantly residential and small commercial 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 April 8, 2013, the NHPUC issued an order conditionally approving a PSNH settlement with OCA and PUC staff for an Alternative Default Energy (ADE) pilot program rate which was designed to address customer migration. The NHPUC condition was accepted by the Settling Parties and incorporated into the initial implementation of Rate ADE in mid-2013. The pilot program results in no impact to earnings and allows for an increased contribution to fixed costs for all ES customers. 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 the customers on third party supply may migrate back to PSNH.

On January 18, 2013, the NHPUC opened a docket to investigate market conditions affecting PSNH s ES 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. On July 15, 2013, the NHPUC accepted from the NHPUC Staff a "Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impact on the Competitive Electricity Market." The report recommended that the NHPUC examine whether default service rates remain sustainable on a going forward basis, define "just and reasonable" with respect to default service in the context of competitive retail markets, analyze the current and expected value of PSNH s generating units, and identify means to mitigate and address stranded cost recovery.

On September 18, 2013, the NHPUC issued a Request for Proposal to hire a valuation expert to determine the value of PSNH's generation assets and entitlements. On October 16, 2013, the State of New Hampshire Legislative Oversight Committee on Electric

Utility Restructuring (Oversight Committee) requested that the NHPUC conduct an analysis to determine whether it is now in the economic interest of PSNH s retail customers for PSNH to divest its interest in generation plants. On November 1, 2013, the Oversight Committee asked for a preliminary report on the findings by April 1, 2014 that would include at a minimum the NHPUC Staff s position, the analysis of the valuation expert, and any recommendations for legislation that may be needed concerning divestiture or otherwise related to this issue. A valuation expert has been hired and the investigation is currently ongoing. At this time, we cannot predict the outcome of this review. Our current PSNH generation rate base totals approximately $760 million. We continue to believe all costs and generation investments are probable of recovery.

On June 28, 2010, the NHPUC approved a joint settlement of PSNH's distribution 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 a defined series of step increases. In 2013, PSNH filed for a distribution rate step increase. On June 27, 2013, the NHPUC approved an increase to rates of $12.6 million, effective July 1, 2013. The increase consists primarily of $7.7 million related to net plant additions and a $5 million increase to the current level of funding for the Major Storm Cost reserve.

The rates established by the NHPUC for PSNH include the following:

.

An energy charge for customers who are not taking power from competitive energy suppliers. The default energy service charge, or ES rate, is charged to customers who have never chosen competitive energy supply. This charge recovers the costs of PSNH s generation as well as purchased power and includes the NHPUC allowed ROE of 9.81 percent on PSNH s generation investment. Rate ADE is charged to certain customers who have returned to PSNH from competitive energy supply. This rate allows PSNH to recover the forecast marginal cost of energy plus an adder for fixed costs.

.

A distribution charge, which includes an energy and/or demand-based charge to recover costs related to the maintenance and operation of PSNH s infrastructure to deliver power to its destination, as well as power restoration and service costs. This includes a customer charge to collect the cost of providing service to a customer; such as the installation, maintenance, reading and replacement of meters and maintaining accounts and records.

.

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

.

A stranded cost recovery charge (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 had 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 the life of the RRBs. The costs of the RRBs, which were retired on May 1, 2013, were recovered through the SCRC rate.

.

A system benefits charge which funds energy efficiency programs for all customers as well as assistance programs for residential customers within certain income guidelines.

.

An electricity consumption tax which is a state mandated tax on energy consumption.

The energy charge and SCRC rates change semi-annually and are reconciled annually. Expense/revenue reconciliation amounts for the energy charge and SCRC are recovered in subsequent rates. The Rate ADE reconciliation amount is incorporated into the ES reconciliation.

Sources and Availability of Electric Power Supply

During 2013, approximately 68 percent of PSNH s load was met through its own generation, long-term power supply provided pursuant to orders of the NHPUC, and contracts with third parties. The remaining 32 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 2014 in a similar manner. Included in the 68 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.

2013, 2012 and 2011 Major Storms

Over the past three years, CL&P, NSTAR Electric, PSNH and WMECO each experienced significant storms, including Tropical Storm Irene, the October 2011 snowstorm, Storm Sandy, and the February 2013 blizzard. As a result of these storms, each electric utility company suffered damage to its distribution and transmission systems, which caused customer outages and required the incurrence of costs to repair significant damage and restore customer service.

The magnitude of these storm restoration costs met the criteria for cost deferral in Connecticut, Massachusetts, and New Hampshire. As a result, the storms had no material impact on the results of operations of CL&P, NSTAR Electric, PSNH and WMECO. We believe our response to each of these 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 electric utility company is seeking recovery of its deferred storm restoration costs through its applicable regulatory recovery process.

CL&P 2013 Storm Filing: In March 2013, CL&P filed a request with PURA for approval to recover storm restoration costs associated with five major storms, all of which occurred in 2011 and 2012. CL&P's deferred storm restoration costs associated with these major storms totaled $462 million. Of that amount, approximately $414 million is subject to recovery in rates after giving effect to CL&P s agreement to forego the recovery of $40 million of previously deferred storm restoration costs as well as an existing storm reserve fund balance of approximately $8 million. During the second half of 2013, the PURA proceeded with the storm recovery review issuing discovery, holding hearings and ultimately on February 3, 2014, issuing a draft decision on the level of storm costs recovery.

In its draft decision, the PURA approved recovery of $365 million of deferred storm restoration costs and ordered CL&P to capitalize approximately $18 million of the deferred storm restoration costs as utility plant, which will be included in depreciation expense in future rate proceedings. PURA will allow recovery of the $365 million with carrying charges in CL&P s distribution rates over a six year period beginning December 1, 2014. The remaining costs were either disallowed or are probable of recovery in future rates and did not have a material impact on CL&P s financial position, results of operations or cash flows. The final decision is expected from PURA in the first quarter of 2014.

NSTAR Electric 2013 Storm Filing: On December 30, 2013, the DPU approved NSTAR Electric s request to recover storm restoration costs, plus carrying costs, related to Tropical Storm Irene and the October 2011 snowstorm. The DPU approved recovery of $34.2 million of the $38 million requested costs. NSTAR Electric will recover these costs, plus carrying costs, in its distribution rates over a five-year period that commenced on January 1, 2014.

PSNH Major Storm Cost Reserve: On June 27, 2013, the NHPUC approved an increase to PSNH s distribution rates effective July 1, 2013 that included a $5 million increase to the current level of funding for the major storm cost reserve.

WMECO SRRCA Mechanism: WMECO has an established Storm Reserve Recovery Cost Adjustment (SRRCA) mechanism to recover the restoration costs associated with its major storms. Effective January 1, 2012, WMECO began recovering the restoration costs of Tropical Storm Irene and other storms that took place prior to August 2011. On August 30, 2013, WMECO submitted its 2013 Annual SRRCA filing to begin recovering the restoration costs associated with the October 2011 snowstorm and Storm Sandy. On December 20, 2013, the DPU approved the 2013 Annual SRRCA filing for effect on January 1, 2014, subject to further review and reconciliation.

2013, 2012 and 2011 Major Storm Deferrals: As of December 31, 2013, the storm restoration costs deferred for recovery from customers for major storms that occurred during 2013, 2012 and 2011 at CL&P, NSTAR Electric, PSNH, and WMECO were as follows:

(Millions of Dollars)	**2013**	**Total**

	2012 and 2011		
	$	$	$
CL&P	365.0	28.8	393.8
NSTAR Electric	61.3	63.6	124.9
PSNH	33.7	5.3	39.0
WMECO	35.3	-	35.3
	$	$	$
Total	495.3	97.7	593.0

ELECTRIC TRANSMISSION SEGMENT

General

Each of CL&P, NSTAR Electric, PSNH and WMECO owns and maintains transmission facilities that are part of an interstate power transmission grid over which electricity is transmitted throughout New England. Each of CL&P, NSTAR Electric, PSNH and WMECO, and most other New England utilities, are parties to a series of agreements that provide for coordinated planning and operation of the region's transmission facilities and the rules by which they acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent of all market participants, serves as the regional transmission organization of the New England transmission system.

Wholesale Transmission Revenues

A summary of NU s wholesale transmission revenues is as follows:

(Millions of Dollars)		**2013**
CL&P	$	506.1
NSTAR Electric		253.6
PSNH		102.5
WMECO		116.5
Total Wholesale Transmission Revenues	$	978.7

Wholesale Transmission Rates

Wholesale transmission revenues are recovered through FERC approved formula rates. Transmission revenues are collected from New England customers, the majority of which are distribution customers of CL&P, NSTAR Electric, PSNH and WMECO. The transmission rates provide for the annual reconciliation and recovery or refund of estimated to actual costs. The financial impacts of differences between actual and estimated costs are deferred for future recovery from, or refunded to, transmission customers.

FERC Base ROE Complaint

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 NETOs, 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 October 1, 2011. In response, the NETOs filed testimony and analysis based on standard FERC methodology and precedent demonstrating that the base ROE of 11.14 percent remained just and reasonable. The FERC set the case for trial before a FERC ALJ after settlement negotiations were unsuccessful in August 2012.

Hearings before the FERC ALJ were held in May 2013, followed by the filing of briefs by the complainants, the Massachusetts municipal electric utilities (late interveners to the case), the FERC trial staff and the NETOs. The NETOs recommended that the current base ROE of 11.14 percent should remain in effect for the refund period (October 1, 2011 through December 31, 2012) and the prospective period (beginning when FERC issues its final decision). The complainants, the Massachusetts municipal electric utilities, and the FERC trial staff each recommended a base ROE of 9 percent or below.

On August 6, 2013, the FERC ALJ issued an initial decision, finding that the base ROE in effect from October 2011 through December 2012 was not reasonable under the standard application of FERC methodology, but leaving policy considerations and additional adjustments to the FERC. Using the established FERC methodology, the FERC ALJ determined that separate base ROEs should be set for the refund period and the prospective period. The FERC ALJ found those base ROEs to be 10.6 percent and 9.7 percent, respectively. The FERC may adjust the prospective period base ROE in its final decision to reflect movement in 10-year Treasury bond rates from the date that the case was filed (April 2013) to the date of the final decision. The parties filed briefs on this decision with the FERC, and a decision from the FERC is expected in 2014. Though NU cannot predict the ultimate outcome of this proceeding, in 2013 the Company recorded a series of reserves at its electric subsidiaries to recognize the potential financial impact from the

FERC ALJ's initial decision for the refund period. The aggregate after-tax charge to earnings totaled $14.3 million at NU, which represents reserves of $7.7 million at CL&P, $3.4 million at NSTAR Electric, $1.4 million at PSNH and $1.8 million at WMECO.

On December 27, 2012, several additional parties filed a separate complaint concerning the NETOs' base ROE with the FERC. This complaint seeks to reduce the NETOs base ROE effective January 1, 2013, effectively extending the refund period for an additional 15 months, and to consolidate this complaint with the joint complaint filed on September 30, 2011. The NETOs have asked the FERC to reject this complaint. The FERC has not yet acted on this complaint, and management is unable to predict the ultimate outcome or estimate the impacts of this complaint on the financial position, results of operations or cash flows.

As of December 31, 2013, the CL&P, NSTAR Electric, PSNH, and WMECO aggregate shareholder equity invested in their transmission facilities was approximately $2.3 billion. As a result, each 10 basis point change in the prospective period authorized base ROE would change annual consolidated earnings by an approximate $2.3 million.

Transmission Projects

NEEWS: GSRP, the first, largest and most complicated project within the NEEWS family of projects was fully energized on November 20, 2013. The project involved the construction of 115 kV and 345 kV overhead lines by CL&P and WMECO from Ludlow, Massachusetts to Bloomfield, Connecticut. This transmission upgrade ensures the reliable flow of power in and around the southern New England area and enables access to less expensive generation, further reducing the risk of congestion costs impacting New England customers. The project was fully energized ahead of schedule with a final cost of $676 million, $42 million under the $718 million estimated cost. As of December 31, 2013, CL&P and WMECO have placed $628.2 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 the second major NEEWS project. All siting applications have been filed by CL&P and National Grid. The Connecticut and Rhode Island portions of the project have been approved and a siting approval decision in Massachusetts is expected in early 2014. On February 12, 2014, the Army Corps of Engineers issued its permit enabling construction on the Connecticut portion of the project. This is the final permit for the Connecticut portion of the project. NU s portion of the cost is estimated to be $218 million and the project is expected to be placed in service in late 2015.

The Greater Hartford Central Connecticut Study (GHCC), which includes the reassessment of the Central Connecticut Reliability Project, continues to make progress. The final need results, which were presented to the ISO-NE Planning Advisory Committee in November 2013, showed existing and worsening severe regional and local thermal overloads and voltage violations within and across each of the four study areas. ISO-NE is expected to confirm the preferred transmission solutions in the first half of 2014, which are likely to include many 115 kV upgrades. We continue to expect that the specific future projects being identified to address these reliability concerns will cost approximately $300 million and that the project will be placed in service in 2017.

Included as part of NEEWS are associated reliability related projects, $90.8 million of which have been placed in service. As of December 31, 2013, the remaining construction on the associated reliability related projects totaled $2.8 million, which is scheduled to be completed by mid-2014.

Through December 31, 2013, CL&P and WMECO capitalized $252.8 million and $567 million, respectively, in costs associated with NEEWS, of which $40.8 million and $48.9 million, respectively, were capitalized in 2013.

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 crosses the Cape Cod Canal and associated 115 kV upgrades in the center of Cape Cod (Lower SEMA Project) and related 115 kV projects (Mid-Cape Project). The Lower SEMA Project line work was completed and placed into service in 2013. The Mid-Cape Project is scheduled to be completed in 2017. The aggregate estimated construction cost for the Cape Cod projects is expected to be approximately $150 million. Through December 31, 2013, NSTAR Electric has invested $96 million in costs associated with the Cape Cod Reliability Projects, of which $61 million was capitalized in 2013.

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. The $1.4 billion project is subject to comprehensive federal and state public permitting processes and is expected to be operational by mid-2017. On July 1, 2013, NPT filed an amendment to the DOE Presidential Permit Application for a proposed improved route in the northernmost section of the project area. As of December 31, 2013, the DOE had completed its public scoping meeting process and the majority of its seasonal field work and environmental data collection. NPT expects to file its state permit application in the fourth quarter of 2014 after the DOE s draft Environmental Impact Statement (EIS) is received.

NPT filed an amendment to the Transmission Services Agreement (TSA) with FERC on December 11, 2013, which was accepted by the FERC on January 13, 2014. The TSA amendment that went into effect on February 14, 2014 extended certain deadlines to provide project flexibility and eliminated a penalty payment for termination of the project in the future.

On December 31, 2013, NPT received ISO-NE approval under Section I.3.9 of the ISO tariff. By approving the project s Section I.3.9 application, ISO-NE determined that Northern Pass can reliably interconnect with the New England grid with no significant, adverse effect on the reliability or operating characteristics of the regional energy grid and its participants.

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 expect projected costs to be approximately $440 million on these new 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 2013, our estimated transmission rate base was approximately $4.4 billion, including approximately $2.2 billion at CL&P, $1.1 billion at NSTAR Electric, $468 million at PSNH, and $597 million at WMECO.

NATURAL GAS DISTRIBUTION SEGMENT

The following table shows the sources of the 2013 natural gas franchise retail revenues of NSTAR Gas and Yankee Gas based on categories of customers:

	NSTAR Gas		Yankee Gas	
(Thousands of Dollars, except percentages)	**2013**	**% of Total**	**2013**	**% of Total**
Residential	$ 250,270	63	$ 217,843	54
Commercial	132,730	33	129,788	32
Industrial	17,625	4	57,951	14
Total Retail Natural Gas Revenues	$ 400,625	100%	$ 405,582	100%

A summary of NSTAR Gas and Yankee Gas retail firm natural gas sales and percentage changes in million cubic feet for 2013, as compared to 2012, is as follows:

	NSTAR Gas[1]			Yankee Gas		
	2013	**2012**	**Percentage Change**	**2013**	**2012**	**Percentage Change**
Residential	21,911	18,385	19.2%	14,866	12,488	19.0%
Commercial	21,341	19,095	11.8%	18,874	16,567	13.9%
Industrial	5,773	5,205	10.9%	15,493	15,787	(1.9%)
Total	49,025	42,685	14.9%	49,233	44,842	9.8%
Total, Net of Special Contracts [2]				45,059	39,087	15.3%

(1)

NSTAR Gas sales data for the full-year ended December 31, 2012 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 2013 consolidated firm natural gas sales are subject to many of the same influences as our retail electric sales, but have benefitted from favorable natural gas prices and customer growth across all three customer classes. Our 2013 consolidated firm natural gas sales were higher, as compared to 2012, due primarily to colder weather in the first and fourth quarters of 2013. The 2013 weather-normalized NU consolidated total firm natural gas sales increased 0.9 percent, as compared to 2012, due primarily to residential customer growth, an increase in natural gas conversions, the migration of interruptible customers switching to firm service rates, and the addition of gas-fired distributed generation, all of which was primarily in the Yankee Gas service territory.

NSTAR GAS

NSTAR Gas distributes natural gas to approximately 274,000 customers in 51 communities in central and eastern Massachusetts covering 1,067 square miles. Total throughput (sales and transportation) in 2013 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.

Predominantly all residential customers in the NSTAR Gas service territory buy gas supply and delivery from NSTAR Gas while all customers may choose their gas suppliers. NSTAR Gas offers firm transportation service to all customers who purchase gas from sources other than NSTAR 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 NSTAR Gas can interrupt service during peak demand periods or at any other time to maintain distribution system integrity.

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 merger settlement agreement provided for a rate freeze through 2015.

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.

NSTAR Gas is subject to SQ metrics that measure safety, reliability and customer service and could be required to pay to customers a SQ charge of up to 2.5 percent of annual distribution revenues for failing to meet such metrics. NSTAR Gas will not be required to pay a SQ charge for its 2013 performance as it achieved results at or above target for all of its SQ metrics in 2013.

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 the Gulf Coast, Mid-continent region, 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 Yankee Energy Systems, Inc. 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

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 218,000 customers in 71 cities and towns), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in 2013 was approximately 55 Bcf. Yankee Gas provides firm natural gas sales service to retail customers who require a continuous natural gas supply throughout the year, such as residential customers who rely on natural 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

14

.

Conservation Adjustment Mechanism (CAM), which allows 100 percent recovery of conservation costs through this mechanism including program incentives to promote energy efficiency, as well as recovery of any lost revenues associated with implementation of energy conservation measures. A reconciliation of CAM revenue to expenses is performed annually with any difference being recovered or refunded with carrying charges in future customer rates the following 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.

PROJECTED CAPITAL EXPENDITURES

We project to make capital expenditures of approximately $7.6 billion from 2014 through 2017. Of the $7.6 billion, we expect to invest approximately $3.5 billion in our electric and natural gas distribution segments and $3.7 billion in our electric transmission segment. In addition, we project to invest approximately $400 million for our corporate service companies.

FINANCING

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, NSTAR Electric, NSTAR Gas, 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 of these companies currently are, and expect to remain, in compliance with these covenants.

As of December 31, 2013, a total of $501.7 million of NU's long-term debt will be paid in the next 12 months, consisting of $150 million for CL&P, $301.7 million for NSTAR Electric and $50 million or PSNH.

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.

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 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.

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.

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 2013, the total RPS obligation was 11.65 percent and it will ultimately reach 24.8 percent in 2025. Energy suppliers, like PSNH, purchase RECs from producers that generate energy from a qualifying resource and use them to satisfy the RPS requirements. PSNH also owns renewable sources and uses a portion of internally generated RECs and purchased RECs to meet its RPS obligations. To the extent that PSNH is unable to purchase sufficient RECs, it makes up the difference between the RECs purchased and its total obligation by making an alternative compliance payment for each REC requirement for which PSNH is deficient. The costs of both the RECs and alternative compliance payments are recovered by PSNH through its ES rates charged to customers.

The RECs generated from PSNH s Northern Wood Power Project, a wood-burning facility, are 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.

Similarly, Connecticut's RPS statute requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2013, the total RPS obligation was 17 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 2013, the requirement was 15.1 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 laws and regulations 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, 2013, 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 $35.4 million, representing 68 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 $31.4 million of the total $35.4 million as of December 31, 2013. Predominantly all of these MGP costs are recoverable from customers through our rates.

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.

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 respective generation 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 that 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.

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.

EMPLOYEES

As of December 31, 2013, NU employed a total of 8,697 employees, excluding temporary employees, of which 1,566 were employed by CL&P, 1,025 were employed by PSNH, 308 were employed by WMECO, and 2,194 were employed by NSTAR Electric. Approximately 48 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, 107 Selden Street, Berlin, CT 06037.

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.

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.

18

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, 2013, goodwill totaled $3.5 billion, of which $3.2 billion was attributable to the acquisition of NSTAR in April 2012. Total goodwill represented approximately 36 percent of our $9.6 billion of shareholders equity and approximately 13 percent of our total assets of $27.8 billion. We test our goodwill balances 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. The annual goodwill impairment test in 2013 resulted in a conclusion that goodwill is not impaired.

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

Severe weather, such as ice and snow storms, hurricanes and other natural disasters, may cause outages and property damage, which may require us to incur additional costs that may not be recoverable from customers. The cost of repairing damage to our operating subsidiaries' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial, particularly as customers demand better and quicker response times to outages. 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 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.

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. 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 included in 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 energy supply 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, which could have an adverse impact on its financial position, results of operations and cash flows.

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. 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, in 2013, NU made contributions to the NUSCO Pension Plan totaling $202.7 million and NSTAR Electric contributed $82 million to the NSTAR Pension Plan. We expect to make contributions in 2014 totaling $71.6 million. 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, 2013, NU and our electric operating subsidiaries owned the following:

NU	**Electric Distribution**	**Electric Transmission**
Number of substations owned	520	62
Transformer capacity (in kVa)	41,928,000	17,827,000
Overhead lines (distribution in pole miles and transmission in circuit miles)	52,022	3,870

Capacity range of overhead transmission lines (in kV)		69 to 345
Underground lines (distribution in conduit bank miles and transmission in cable miles)	12,785	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	183	19	138	20	156	15	43	
Transformer capacity (in kVa)	18,951,000	3,117,000	11,374,000	9,575,000	7,617,000	3,868,000	3,986,000	1,26
Overhead lines (distribution in pole miles and transmission in circuit miles)	18,375	1,654	16,579	708	13,274	1,003	3,794	
Capacity range of overhead transmission lines (in kV)		69-345		115-345		115-345		6
Underground lines (distribution in conduit bank miles and transmission in cable miles)	1,171	402	9,592	243	1,730	1	292	
Capacity range of underground transmission lines (in kV)		69-345		115-345		115		

	NU	CL&P	NSTAR Electric	PSNH	WMECO
Underground and overhead line transformers in service	627,962	286,922	131,500	166,866	42,674

Aggregate capacity (in kVa)	34,361,049	14,946,332	10,289,291	7,024,239	2,101,187

Electric Generating Plants

As of December 31, 2013, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (kilowatts)
Fossil Steam Plants	5 units	1952-74	935,343
Hydro	20 units	1901-83	60,736
Internal Combustion	5 units	1968-70	101,868
Biomass	1 unit	2006	42,594
Total PSNH Generating Plant	31 units		1,140,541

*

Claimed capability represents winter ratings as of December 31, 2013. The combined nameplate capacity of the generating plants is approximately 1,200 MW.

As of December 31, 2013, WMECO owned the following electric generating plants:

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

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

CL&P and NSTAR Electric do not own any electric generating plants.

Natural Gas Distribution System

As of December 31, 2013, Yankee Gas owned 28 active gate stations, 206 district regulator stations, and 3,291 miles of natural gas main pipeline. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut.

As of December 31, 2013, NSTAR Gas owned 21 active gate stations, 145 district regulator stations, and 3,213 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

24

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 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

DOE Phase I Damages 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). Phase I covered damages for the period 1998 through 2002. Following multiple appeals and cross-appeals in December 2012, the judgment awarding CYAPC $39.6 million, YAEC $38.3 million and MYAPC $81.7 million became final.

In January 2013, the proceeds from the DOE Phase I Damages Claim were received by the Yankee Companies and transferred to each Yankee Company s respective decommissioning trust. As a result of NU's consolidation of CYAPC and YAEC, the financial statements reflected an increase of $77.9 million in marketable securities for CYAPC and YAEC s Phase I damage awards that were invested in the nuclear decommissioning trusts in 2013.

On May 1, 2013, CYAPC, YAEC and MYAPC filed applications with the FERC to reduce rates in their wholesale power contracts through the application of the DOE proceeds for the benefit of customers. In its June 27, 2013 order, the FERC granted the proposed rate reductions, and changes to the terms of the wholesale power contracts to become effective on July 1, 2013. In accordance with the FERC order, CL&P, NSTAR Electric, PSNH and WMECO began receiving the benefit of the DOE proceeds, and the benefits have been or will be passed on to customers.

DOE Phase II Damages - 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.

On November 15, 2013, the court issued a final judgment awarding CYAPC $126.3 million, YAEC $73.3 million, and MYAPC $35.8 million. On January 14, 2014, the Yankee Companies received a letter from the U.S. Department of Justice stating that the DOE will not appeal the court's final judgment. As of December 31, 2013, CL&P, NSTAR Electric, PSNH, WMECO, CYAPC, and YAEC have not reflected the impact of these expected receivables on their financial statements.

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

DOE Phase III Damages On August 15, 2013, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred in the years 2009 through 2012. Responsive pleading from the Department of Justice was filed on November 18, 2013, and discovery is expected to begin once a protective order is in place.

2.

Conservation Law Foundation v. PSNH

On July 21, 2011, the Conservation Law Foundation (CLF) filed a citizens suit under the provisions of the federal Clean Air Act against PSNH alleging permitting violations at the company s Merrimack generating station. The suit alleges that PSNH failed to have proper permits for replacement of the Unit 2 turbine at Merrimack, 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. The case is expected to proceed to trial over the course of the next two years.

3.

Other Legal Proceedings

For further discussion of legal proceedings, see Item 1, *Business:* "- Electric Distribution Segment," "- Electric Transmission Segment," and "- Natural Gas Distribution 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.

Item 4.

Mine Safety Disclosures

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the executive officers of NU as of February 15, 2014. 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	44	Vice President, Controller and Chief Accounting Officer.
Gregory B. Butler	56	Senior Vice President, General Counsel and Secretary.
Christine M. Carmody*	51	Senior Vice President-Human Resources of NUSCO.
James J. Judge	58	Executive Vice President and Chief Financial Officer.
Thomas J. May	66	Chairman of the Board, President and Chief Executive Officer.
David R. McHale	53	Executive Vice President and Chief Administrative Officer.
Joseph R. Nolan, Jr.*	50	Senior Vice President-Corporate Relations of NUSCO.
Leon J. Olivier	65	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 has served as Vice President, Controller and Chief Accounting Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012. Previously, Mr. Buth served as Vice President-Accounting and Controller of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from June 2009 until April 10, 2012. From June 2006 through January 2009, Mr. Buth served as 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 has served as Senior Vice President, General Counsel and Secretary of NU and Senior Vice President and General Counsel of NSTAR Electric and NSTAR Gas since April 10, 2012. 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 has served as a Director of NSTAR Electric and NSTAR Gas since April 10, 2012. 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 10, 2012. Mr. Butler has served as a Trustee of the NSTAR Foundation since April 10, 2012. He has served as a Director of Northeast Utilities Foundation, Inc. since December 1, 2002.

Christine M. Carmody. Ms. Carmody has served as Senior Vice President-Human Resources of NUSCO since April 10, 2012 and of CL&P, PSNH, WMECO and Yankee Gas since November 27, 2012. She has served as Senior Vice President-Human Resources of NSTAR Electric and NSTAR Gas since August 1, 2008. Ms. Carmody has served as a Director of CL&P, PSNH, WMECO and Yankee Gas since April 10, 2012, and of NSTAR Electric, NSTAR Gas, and NUSCO since November 27, 2012. Previously, Ms. Carmody served as Vice President-Organizational Effectiveness of NSTAR, NSTAR Electric and NSTAR Gas from June 2006 to August 2008. Ms. Carmody has served as a Director of Northeast Utilities Foundation, Inc. since April 10, 2012. She has served as a Trustee of the NSTAR Foundation since August 1, 2008.

James J. Judge. Mr. Judge has served as Executive Vice President and Chief Financial Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012. Mr. Judge has served as a Director of CL&P, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012. He has served as a Director of NSTAR Electric and NSTAR Gas since September 27, 1999. Previously, Mr. Judge served as Senior Vice President and Chief Financial Officer of NSTAR, NSTAR Electric and NSTAR Gas from 1999 until April 2012. Mr. Judge has served as Treasurer and a Director of Northeast Utilities Foundation, Inc. since April 10, 2012. He has served as a Trustee of the NSTAR Foundation since December 12, 1995.

Thomas J. May. Mr. May has served as Chairman of the Board of NU since October 10, 2013, and 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 since April 10, 2012. Mr. May has served as a Director of NSTAR Electric and NSTAR 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 and NSTAR Gas until April 10, 2012. He served as Chairman, Chief Executive Officer and a Trustee since NSTAR was formed in 1999, and was elected President in 2002. Mr. May has served as Chairman of the Board and President of Northeast Utilities Foundation, Inc. since October 15, 2013, and has served as a Director of Northeast Utilities Foundation, Inc. since April 10, 2012. He has served as a Trustee of the NSTAR Foundation since August 18, 1987.

David R. McHale. Mr. McHale has served as Executive Vice President and Chief Administrative Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012. Mr. McHale has served as a Director of NSTAR Electric and NSTAR 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 has served as a Trustee of the NSTAR Foundation since April 10, 2012. He has served as a Director of Northeast Utilities Foundation, Inc. since January 1, 2005.

Joseph R. Nolan, Jr. Mr. Nolan has served as Senior Vice President-Corporate Relations of NSTAR Electric, NSTAR Gas and NUSCO since April 10, 2012. He has served as Senior Vice President-Corporate Relations of CL&P, PSNH, WMECO and Yankee Gas since November 27, 2012. Mr. Nolan has served as a Director of CL&P, PSNH, WMECO and Yankee Gas since April 10, 2012, and of NSTAR Electric, NSTAR Gas and NUSCO since November 27, 2012. Previously, Mr. Nolan served as Senior Vice President-Customer & Corporate Relations of NSTAR, NSTAR Electric and NSTAR Gas from 2006 until April 10, 2012. Mr. Nolan has served as a Director of Northeast Utilities Foundation, Inc. since April 10, 2012, and has served as Executive Director of Northeast Utilities Foundation, Inc. since October 15, 2013. 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. He became Chief Executive Officer of NSTAR Electric and NSTAR Gas on April 10, 2012. Mr. Olivier has served as Chief Executive Officer of CL&P, PSNH, WMECO and Yankee Gas since January 15, 2007. Mr. Olivier has served as a Director of NSTAR Electric and NSTAR Gas since November 27, 2012, of PSNH, WMECO and Yankee Gas since 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 has served as a Trustee of the NSTAR Foundation since April 10, 2012. He has served as a Director of Northeast Utilities Foundation, Inc. since April 1, 2006.

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
2013	First	$ 43.49	$ 38.60	$ 0.368
	Second	45.66	39.35	0.368
	Third	45.13	40.01	0.368
	Fourth	43.75	40.60	0.368
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

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 2013 and 2012, CL&P approved and paid $152 million and $100.5 million, respectively, of common stock dividends to NU.

During 2013, NSTAR Electric approved and paid $56 million of common stock dividends to its parent company. For the period April 10, 2012 to December 31, 2012, NSTAR Electric approved and paid $159.9 million of common stock dividends to its parent company.

During 2013 and 2012, PSNH approved and paid $68 million and $90.7 million, respectively, of common stock dividends to NU.

During 2013 and 2012, WMECO approved and paid $40 million and $9.4 million, respectively, of common stock dividends to NU.

(b)

Holders

As of January 31, 2014, there were 46,983 registered common shareholders of our company on record. As of the same date, there were a total of 315,434,940 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

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in 2008 in Northeast Utilities common stock, as compared with the S&P 500 Stock Index and the EEI Index for the period 2009 through 2013, assuming all dividends are reinvested.

(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, 2013	-	$ -	-	-
November 1 - November 30, 2013	-	-	-	-
December 1 - December 31, 2013	75,700	42.22	-	-

Total	75,700	$	42.22	-	-

29

Item 6.

Selected Consolidated Financial Data

NU Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and common share information)	2013	2012 [(a)]	2011	2010	2009
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 17,576,186	$ 16,605,010	$ 10,403,065	$ 9,567,726	$ 8,839,965
Total Assets	27,795,537	28,302,824	15,647,066	14,472,601	14,057,679
Total Capitalization (b) (c)	18,077,274	17,356,112	9,078,321	8,627,985	8,253,323
Obligations Under Capital Leases (b)	10,744	11,071	12,358	12,236	12,873
Income Statement Data:					
Operating Revenues	$ 7,301,204	$ 6,273,787	$ 4,465,657	$ 4,898,167	$ 5,439,430
Net Income	793,689	533,077	400,513	394,107	335,592
Net Income Attributable to Noncontrolling Interests	7,682	7,132	5,820	6,158	5,559
Net Income Attributable to Controlling Interest	$ 786,007	$ 525,945	$ 394,693	$ 387,949	$ 330,033
Common Share Data:					
Basic Earnings Per Common Share:					
Net Income Attributable to Controlling Interests	$ 2.49	$ 1.90	$ 2.22	$ 2.20	$ 1.91
Diluted Earnings Per Common Share:					
Net Income Attributable to Controlling Interest	$ 2.49	$ 1.89	$ 2.22	$ 2.19	$ 1.91
Weighted Average Common Shares Outstanding					
Basic	315,311,387	277,209,819	177,410,167	176,636,086	172,567,928

Diluted		316,211,160		277,993,631		177,804,568		176,885,387		172,717,246
Dividends Declared Per Share	$	1.47	$	1.32	$	1.10	$	1.03	$	0.95
Market Price - Closing (high) (d)	$	45.33	$	40.57	$	36.31	$	32.05	$	26.33
Market Price - Closing (low) (d)	$	38.67	$	33.53	$	30.46	$	24.78	$	19.45
Market Price - Closing (end of year) (d)	$	42.39	$	39.08	$	36.07	$	31.88	$	25.79
Book Value Per Share (end of year)	$	30.49	$	29.41	$	22.65	$	21.60	$	20.37
Tangible Book Value Per Share (end of year) (e)	$	19.32	$	18.21	$	21.03	$	19.97	$	18.74
Rate of Return Earned on Average Common Equity (%) (f)		8.3		7.9		10.1		10.7		10.2
Market-to-Book Ratio (end of year) (g)		1.4		1.3		1.6		1.5		1.3
Capitalization:										
Total Equity		53 %		53 %		44 %		44 %		44 %
Preferred Stock, not subject to mandatory redemption		1		1		1		1		1
Long-Term Debt (b) (c)		46		46		55		55		55
		100 %		100 %		100 %		100 %		100 %

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.
(b) Includes portions due within one year.
(c) Excludes RRBs.
(d) Market price information reflects closing prices as reflected by the New York Stock Exchange.
(e) Common Shareholder's Equity adjusted for goodwill and intangibles divided by total common shares outstanding.
(f) Net Income Attributable to Controlling Interest divided by average Common Shareholders' Equity.
(g) The closing market price divided by the book value per share.

CL&P Selected Financial Data (Unaudited)

(Thousands of Dollars)		**2013**		**2012**		**2011**		**2010**		**2009**
Operating Revenues	$	2,442,341	$	2,407,449	$	2,548,387	$	2,999,102	$	3,424,538
Net Income		279,412		209,725		250,164		244,143		216,316
Cash Dividends on Common Stock		151,999		100,486		243,218		217,691		113,848
		6,451,259		6,152,959		5,827,384		5,586,504		5,340,561

Property, Plant and Equipment, Net					
Total Assets	8,980,502	9,142,088	8,791,396	8,255,192	8,364,564
Rate Reduction Bonds	-	-	-	-	195,587
Long-Term Debt (a) (b)	2,741,208	2,862,790	2,583,753	2,583,102	2,582,361
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	9,309	9,960	10,715	10,613	10,956

(a) Includes portions due within one year.
(b) Excludes RRBs.

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	**2013**	**2012** [(a)]	**2011**	**2010**	**2009**
Revenues: *(Thousands)*					
Residential	$ 3,073,181	$ 2,731,951	$ 2,091,270	$ 2,336,078	$ 2,569,278
Commercial	2,387,535	1,604,661	1,236,374	1,346,228	1,495,821
Industrial	339,917	753,974	252,878	268,598	297,854
Wholesale	486,515	357,223	350,413	506,475	445,261
Miscellaneous and Eliminations	56,547	130,137	47,485	(29,878)	128,118
Total Electric	6,343,695	5,577,946	3,978,420	4,427,501	4,936,332
Natural Gas	855,601	572,857	430,799	434,277	449,571
Total - Regulated Companies	7,199,296	6,150,803	4,409,219	4,861,778	5,385,903
Other and Eliminations	101,908	122,984	56,438	36,389	53,527
Total	$ 7,301,204	$ 6,273,787	$ 4,465,657	$ 4,898,167	$ 5,439,430
Regulated Companies - Sales: *(GWh)*					
Residential	21,896	19,719	14,766	14,913	14,412
Commercial	27,787	24,537	14,628	14,836	14,810
Industrial	5,648	5,462	4,418	4,481	4,423
Wholesale	855	2,154	1,020	3,423	4,183
Total	56,186	51,872	34,832	37,653	37,828
Regulated Companies - Customers: *(Average)*					
Residential	2,718,727	2,711,407	1,710,342	1,704,197	1,696,756
Commercial	371,897	370,389	199,240	198,558	196,813
Industrial	8,109	8,279	7,083	7,150	7,207
Total Electric	3,098,733	3,090,075	1,916,665	1,909,905	1,900,776
Natural Gas	493,563	483,770	207,753	205,885	206,438
Total	3,592,296	3,573,845	2,124,418	2,115,790	2,107,214

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.

CL&P Selected Sales Statistics	**2013**	**2012**	**2011**	**2010**	**2009**
Revenues: *(Thousands)*					
Residential	$ 1,294,160	$ 1,263,845	$ 1,345,290	$ 1,597,754	$ 1,840,750
Commercial	780,585	732,620	758,145	853,956	958,224

Industrial	129,557	126,165	126,783	144,463	151,839
Wholesale	219,367	214,807	278,751	441,660	386,034
Miscellaneous	18,672	70,012	39,418	(38,731)	87,691
Total	$ 2,442,341	$ 2,407,449	$ 2,548,387	$ 2,999,102	$ 3,424,538
Sales: *(GWh)*					
Residential	10,314	9,978	10,092	10,196	9,848
Commercial	9,770	9,705	9,809	10,002	9,991
Industrial	2,320	2,426	2,414	2,467	2,427
Wholesale	851	1,155	1,592	3,040	3,434
Total	23,255	23,264	23,907	25,705	25,700
Customers: *(Average)*					
Residential	1,105,417	1,103,397	1,100,740	1,096,576	1,093,229
Commercial	108,735	108,589	108,235	107,532	107,121
Industrial	3,247	3,301	3,331	3,359	3,381
Total	1,217,399	1,215,287	1,212,306	1,207,467	1,203,731

Item 7.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related combined notes included in this Annual Report on Form 10-K. References in this Annual Report to "NU," the "Company," "we," "us," and "our" refer to Northeast Utilities and its consolidated subsidiaries. All per share amounts are reported on a diluted basis. The consolidated financial statements of NU, NSTAR Electric and PSNH and the financial statements of CL&P and WMECO are herein collectively referred to as the "financial statements."

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 year. The discussion below also includes non-GAAP financial measures referencing our 2013, 2012 and 2011 earnings and EPS excluding certain integration and merger costs related to NU's merger with NSTAR and 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. We use these non-GAAP financial measures to evaluate and to provide details of earnings by business and to more fully compare and explain our 2013, 2012 and 2011 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, we completed our merger with NSTAR. Unless otherwise noted, the results of NSTAR and its subsidiaries, hereinafter referred to as "NSTAR," are included in NU s financial position, results of operations and cash flows as of December 31, 2013 and 2012, for the full year ended December 31, 2013, and for the period beginning April 10, 2012 through December 31, 2012 throughout this *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Executive Summary

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

Results:

.

We earned $786 million, or $2.49 per share, in 2013, compared with $525.9 million, or $1.89 per share, in 2012. Excluding after-tax integration and merger-related costs of $13.8 million, or $0.04 per share, in 2013 and $107.6 million, or $0.39 per share, in 2012, we earned $799.8 million, or $2.53 per share, in 2013 and $633.5 million, or $2.28 per share, in 2012.

.

Our electric distribution segment, which includes generation, earned $427 million, or $1.35 per share, in 2013, compared with $292.3 million, or $1.04 per share, in 2012. The 2012 results include $51.1 million, or $0.19 per share, of after-tax merger settlement agreement costs.

.

Our transmission segment earned $287 million, or $0.91 per share, in 2013, compared with $249.7 million, or $0.90 per share, in 2012.

.

Our natural gas distribution segment earned $60.9 million, or $0.19 per share, in 2013, compared with $30.8 million, or $0.11 per share, in 2012. 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 earnings of $11.1 million, or $0.04 per share, in 2013, compared with net losses of $46.9 million, or $0.16 per share, in 2012. The 2013 and 2012 results include $13.8 million, or $0.04 per share, and $54.4 million, or $0.19 per share, respectively, of after-tax integration and merger-related costs.

.

We project to make capital expenditures of approximately $7.6 billion from 2014 through 2017. Of the $7.6 billion, we expect to invest approximately $3.5 billion in our electric and natural gas distribution segments and $3.7 billion in our electric transmission segment. In addition, we project to invest approximately $400 million for our corporate service companies.

Legislative, Regulatory, Policy and Other Items:

.

In 2013, CL&P and NSTAR Electric filed a request with the PURA and DPU, respectively, seeking approval to recover storm restoration costs. On December 30, 2013, the DPU approved recovery of NSTAR Electric s $34.2 million in storm restoration costs. On February 3, 2014, the PURA issued a draft decision, approving recovery of CL&P s $365 million in storm restoration costs.

.

In 2013, Connecticut enacted into law two significant energy bills. The first law implemented a number of the recommendations proposed in the Connecticut comprehensive energy strategy (CES), including the expansion of natural gas service, and required PURA to implement decoupling for each of Connecticut s electric and natural gas utilities in their next respective rate cases. The second law allows DEEP to conduct a process that will ultimately help Connecticut meet its Renewable Portfolio Standard by authorizing the state s electric distribution companies to enter into long-term power purchase agreements.

.

On November 22, 2013, the PURA issued a final decision approving a comprehensive joint natural gas infrastructure expansion plan (expansion plan), consistent with the goals of the CES, that was filed in June 2013 by Yankee Gas and other Connecticut natural gas distribution companies. The expansion plan described how Yankee Gas expects to add approximately 82,000 new natural gas heating customers over the next 10 years.

.

On July 1, 2013, NPT filed an amendment to the Department of Energy (DOE) Presidential Permit Application for a proposed improved route in the northernmost section of the project area. The DOE completed its public scoping meeting process and the majority of its seasonal field work and environmental data collection. On December 11, 2013, NPT filed an amendment to the Transmission Services Agreement (TSA) with FERC, which was accepted on January 13, 2014. On December 31, 2013, NPT received ISO-NE approval under Section I.3.9 of the ISO tariff.

.

On August 6, 2013, the FERC ALJ issued an initial decision regarding the September 2011 joint complaint filed with the FERC by various New England parties concerning the base ROE earned by New England transmission owners (NETOs). The initial decision found that the current base ROE is not reasonable, but leaves policy considerations and additional adjustments to the FERC, and determined that a separate base ROE of 10.6 percent and 9.7 percent should be set for the refund period (October 1, 2011 through December 31, 2012) and the prospective period (beginning when FERC issues its final decision), respectively. The FERC may adjust the prospective period base ROE in its final decision, expected in 2014, to reflect movement in the capital markets from when the case was filed in April 2013. As a result, in 2013, we recorded a reserve and recognized an after-tax charge of $14.3 million for the potential financial impact from the FERC ALJ's initial decision.

.

On November 20, 2013, GSRP, the first, largest and most complicated project within the NEEWS family of projects was fully energized. The project was fully energized ahead of schedule with a final cost of $676 million, $42 million under the $718 million estimated cost.

Liquidity:

.

Cash and cash equivalents totaled $43.4 million as of December 31, 2013, compared with $45.7 million as of December 31, 2012, while investments in property, plant and equipment totaled $1.5 billion in both 2013 and 2012.

.

Cash flows provided by operating activities in 2013 totaled $1.58 billion, compared with operating cash flows of $1.05 billion in 2012 (amounts are net of RRB payments). The improved cash flows were due primarily to the addition of NSTAR, a decrease in storm restoration costs, and the absence in 2013 of customer bill credits and merger-related costs paid in 2012, partially offset by an increase in Pension Plan cash contributions.

.

In 2013, we issued $1.68 billion of new long-term debt consisting of $750 million by NU parent, $400 million by CL&P, $200 million by NSTAR Electric, $250 million by PSNH, and $80 million by WMECO. These new issuances were used primarily to repay approximately $928 million of existing long-term debt and PCRBs. On January 2, 2014, Yankee Gas issued $100 million of new long-term debt. As of December 31, 2013, approximately $502 million of NU's current liabilities relate to long-term debt that will be paid in the next 12 months.

.

On February 4, 2014, our Board of Trustees approved a common dividend payment of $0.3925 per share, payable on March 31, 2014 to shareholders of record as of March 3, 2014. The dividend represented an increase of 6.8 percent over the quarterly dividend paid in December 2013.

33

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 2013, 2012 and 2011 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars, Except Per Share Amounts)	**2013**		**2012** [1]		**2011**	
	Amount	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income Attributable to Controlling Interest (GAAP)	$ 786.0	$ 2.49	$ 525.9	$ 1.89	$ 394.7	$ 2.22
Regulated Companies	$ 774.9	$ 2.45	$ 626.0	$ 2.25	$ 438.3	$ 2.46
NU Parent and Other Companies	24.9	0.08	7.5	0.03	(14.4)	(0.08)
Non-GAAP Earnings	799.8	2.53	633.5	2.28	423.9	2.38
Integration and Merger-Related Costs (after-tax)	(13.8)	(0.04)	(107.6)	(0.39)	(11.3)	(0.06)
Storm Fund Reserve	-	-	-	-	(17.9)	(0.10)
Net Income Attributable to Controlling Interest (GAAP)	$ 786.0	$ 2.49	$ 525.9	$ 1.89	$ 394.7	$ 2.22

(1)

Results include the operations of NSTAR beginning April 10, 2012.

The 2013 after-tax integration-related costs consisted of costs incurred for employee severance in connection with ongoing integration, and consulting and retention costs. The 2012 after-tax merger-related costs consisted of Regulated companies charges of $53.2 million (for further information, see the *Regulated Companies* portion of this Overview section), costs of $34 million at NU parent related to investment advisory fees, attorney fees, and consulting costs, an $11.5 million charge related to change in control costs and other compensation costs at NU parent, and an $8.9 million charge at NU parent for the establishment of a fund to advance Connecticut energy goals related to the Connecticut merger settlement agreement.

Excluding the impact of the integration and merger-related costs, our 2013 earnings increased by $166.3 million, as compared to 2012, due primarily to the inclusion of NSTAR beginning April 10, 2012, lower overall operations and maintenance costs, higher retail electric and firm natural gas sales, higher transmission segment earnings as a result of increased investments in the transmission infrastructure, and the favorable impact of a lower effective tax rate in 2013 at NU parent. Partially offsetting these favorable earnings impacts were higher depreciation and property tax expense and the establishment of an after-tax reserve of $14.3 million for a potential customer refund related to an August 2013 initial decision from the FERC ALJ. For further information, see "FERC Regulatory Issues - FERC Base ROE Complaint" in this *Management's Discussion and Analysis.*

Regulated Companies: Our Regulated companies consist of the electric distribution, transmission, and natural gas distribution segments. Generation activities of PSNH and WMECO are included in our electric distribution segment. A summary of our segment earnings for 2013, 2012 and 2011 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2013**	**2012** (1)	**2011**
Net Income Regulated Companies (GAAP)	$ 774.9	$ 572.8	$ 420.4
Electric Distribution	$ 427.0	$ 343.4	$ 207.0
Transmission	287.0	249.7	199.6
Natural Gas Distribution	60.9	32.9	31.7
Net Income Regulated Companies (Non-GAAP)	774.9	626.0	438.3
Merger-Related Costs (after-tax) (2)	-	(53.2)	-
Storm Fund Reserve (3)	-	-	(17.9)
Net Income - Regulated Companies (GAAP)	$ 774.9	$ 572.8	$ 420.4

(1)

Results include the operations of NSTAR beginning April 10, 2012.

(2)

Merger-related 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 2012 after-tax merger-related costs consisted of $27.6 million ($46 million pre-tax) in charges at CL&P, NSTAR Electric, NSTAR Gas and WMECO for customer bill credits related to the Connecticut and Massachusetts merger settlement agreements, a $23.6 million ($40 million pre-tax) charge related to the Connecticut merger settlement agreement, whereby CL&P agreed to forego recovery of previously deferred storm restoration costs associated with Tropical Storm Irene and the October 2011 snowstorm, and a $2 million charge related to change in control costs and other compensation costs.

Excluding the impact of the merger-related costs, our electric distribution segment earnings increased in 2013, as compared to 2012, due primarily to the inclusion of NSTAR Electric distribution business earnings, lower overall operations and maintenance costs and higher retail electric sales due primarily to colder weather in the first and fourth quarters of 2013, as compared to the same periods in 2012. The 2013 results were also favorably impacted by PSNH rate increases effective July 1, 2012 and July 1, 2013 as a result of the 2010 distribution rate case settlement. Partially offsetting these favorable earnings impacts were higher depreciation and property tax expense.

Our transmission segment earnings increased in 2013, as compared to 2012, due primarily to the inclusion of NSTAR Electric transmission business earnings, increased investments in our transmission infrastructure, including GSRP, and the favorable impact of a lower effective tax rate in 2013, partially offset by the $14.3 million after-tax reserve related to the August 2013 FERC ALJ initial decision.

Excluding the impact of the merger-related costs, our natural gas distribution segment earnings increased in 2013, as compared to 2012, due primarily to the inclusion of NSTAR Gas earnings, higher firm natural gas sales due primarily to colder weather in the first and fourth quarters of 2013, as compared to the same periods in 2012, as well as the addition of approximately 10,000 new natural gas heating customers in 2013, and the favorable impact related to an increase in Yankee Gas rates effective July 1, 2012 as a result of the Yankee Gas 2011 rate case decision.

A summary of our retail electric GWh sales and percentage changes, assuming NSTAR Electric had been part of the NU electric distribution system for all periods, as well as percentage changes in CL&P, NSTAR Electric, PSNH and WMECO retail electric GWh sales, is as follows:

	For the Year Ended December 31, 2013 Compared to 2012		
	Sales (GWh)		
NU - Electric	**2013**	**2012** [1]	**Percentage Increase/ (Decrease)**
Residential	21,896	21,374	2.4 %
Commercial [2]	27,787	27,647	0.5 %
Industrial	5,648	5,787	(2.4)%
Total	55,331	54,808	1.0 %

	For the Year Ended December 31, 2013 Compared to 2012			
Electric	**CL&P Percentage Increase/ (Decrease)**	**NSTAR Electric Percentage Increase/ (Decrease)**	**PSNH Percentage Increase**	**WMECO Percentage Increase/ (Decrease)**
Residential	3.4 %	1.3 %	2.2%	1.7 %
Commercial [2]	0.7 %	0.4 %	0.6%	(0.4)%
Industrial	(4.4)%	(3.0)%	2.1%	(3.0)%
Total	1.3 %	0.5 %	1.5%	- %

(1)

Results include retail electric sales of NSTAR Electric from January 1, 2012 through December 31, 2012 for comparative purposes only.

(2)

Commercial retail electric GWh sales include streetlighting and railroad retail sales.

A summary of our firm natural gas sales in million cubic feet and percentage changes, assuming NSTAR Gas had been part of the NU natural gas distribution system for all periods, as well as percentage changes in Yankee Gas and NSTAR Gas, for 2013, as compared to 2012, is as follows:

	For the Year Ended December 31, 2013 Compared to 2012		
	Sales (million cubic feet)		Percentage
NU - Firm Natural Gas	**2013**	**2012 (1)**	**Increase**
Residential	36,777	30,873	19.1%
Commercial	40,215	35,662	12.8%
Industrial	21,266	20,992	1.3%
Total	98,258	87,527	12.3%
Total, Net of Special Contracts (2)	94,083	81,772	15.1%

	For the Year Ended December 31, 2013 Compared to 2012 Sales (million cubic feet)	
	Yankee Gas Percentage Increase/(Decrease)	**NSTAR Gas [3] Percentage Increase**
Firm Natural Gas		
Residential	19.0 %	19.2%
Commercial	13.9 %	11.8%
Industrial	(1.9)%	10.9%
Total	9.8 %	14.9%
Total, Net of Special Contracts (2)	15.3 %	

(1)

Results include firm natural gas sales of NSTAR Gas from January 1, 2012 through December 31, 2012 for comparative purposes only.

(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, 2013 compared to 2012 has been provided for comparative purposes only.

Weather, fluctuations in energy supply costs, conservation measures (including company-sponsored energy efficiency programs), and economic conditions affect customer energy usage. Industrial sales are less sensitive to temperature variations than residential and commercial sales. In our service territories, weather impacts electric sales during the summer and electric and natural gas sales during the winter (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. In addition, our electric and natural gas businesses are susceptible to damage from major storms and other natural events and disasters that could adversely affect our ability to provide energy.

Our 2013 consolidated retail electric sales were higher, as compared to 2012, due primarily to colder weather in the first and fourth quarters of 2013. The 2013 retail electric sales for CL&P, NSTAR Electric and PSNH increased while they remained unchanged for WMECO, as compared to 2012, due primarily to colder weather in the first and fourth quarters of 2013. In 2013, heating degree days were 17 percent higher in Connecticut and western Massachusetts, 16 percent higher in the Boston metropolitan area, and 15 percent higher in New Hampshire, and cooling degree days were 7 percent lower in Connecticut and western Massachusetts, 2 percent higher in the Boston metropolitan area, and 9 percent lower in New Hampshire, as compared to 2012. On a weather-normalized basis (based on 30-year average temperatures), 2013 retail electric sales for CL&P and PSNH increased, while they decreased for NSTAR Electric and WMECO, as compared to 2012. The 2013 weather-normalized NU consolidated total retail electric sales remained relatively unchanged, as compared to 2012.

For WMECO, fluctuations in retail electric sales do not impact earnings due to the DPU-approved revenue decoupling mechanism. Under this decoupling mechanism, WMECO has an overall fixed annual level of distribution delivery service revenues of $132.4 million, comprised of customer base rate revenues of $125.4 million and a baseline low income discount recovery of $7 million. These two mechanisms effectively break the relationship between sales volume and revenues recognized.

Our 2013 consolidated firm natural gas sales are subject to many of the same influences as our retail electric sales, but have benefitted from favorable natural gas prices and customer growth across all three customer classes. Our 2013 consolidated firm natural gas sales were higher, as compared to 2012, due primarily to colder weather in the first and fourth quarters of 2013. The 2013 weather-normalized NU consolidated total firm natural gas sales increased 0.9 percent, as compared to 2012, due primarily to residential customer growth, an increase in natural gas conversions, the migration of interruptible customers switching to firm service rates, and the addition of gas-fired distributed generation, all of which was primarily in the Yankee Gas service territory.

NU Parent and Other Companies: NU parent and other companies (which includes certain subsidiaries of NSTAR beginning April 10, 2012, and our competitive businesses held by NU Enterprises) earned $11.1 million in 2013, compared with net losses of $46.9 million in 2012. Excluding the impact of integration and merger-related costs of $13.8 million in 2013 and $54.4 million in 2012, NU parent and other companies earned $24.9 million in 2013, compared with $7.5 million in 2012. Improved 2013 results were due primarily to a lower effective tax rate, a decrease in interest expense at NU parent, and an increase in earnings at the unregulated businesses.

Future Outlook

2014 EPS Guidance: We currently project 2014 earnings of between $2.60 and $2.75 per share.

Liquidity

Consolidated: Cash and cash equivalents totaled $43.4 million as of December 31, 2013, compared with $45.7 million as of December 31, 2012.

CL&P issued $400 million of 2.5 percent 2013 Series A First and Refunding Mortgage Bonds on January 15, 2013, due to mature in 2023. The proceeds, net of issuance costs, were used to pay short-term borrowings outstanding under the CL&P credit agreement of $89 million and intercompany loans related to our commercial paper program of

$305.8 million. On September 3, 2013, CL&P

redeemed at par $125 million of 1.25 percent Series B 2011 PCRBs, which were subject to mandatory tender for purchase, using short-term debt.

NSTAR Electric issued $200 million of three-year floating rate debentures on May 17, 2013, due to mature in 2016. The proceeds, net of issuance costs, were used to pay short-term borrowings and for general corporate purposes.

PSNH redeemed at par approximately $109 million of the 5.45 percent 2001 Series C PCRBs on May 1, 2013, which were due to mature in 2021, using short-term debt. On November 14, 2013, PSNH issued $250 million of 3.50 percent Series S First Mortgage Bonds, due to mature in 2023. On December 23, 2013, PSNH redeemed approximately $89 million of the 4.75 percent Series B PCRBs, which were due to mature in 2021, using a portion of the proceeds from the Series S First Mortgage Bonds. The remaining Series S First Mortgage Bond proceeds were used to pay short-term borrowings.

WMECO repaid at maturity $55 million of 5 percent Series A Senior Notes on September 1, 2013, using short-term debt. On November 15, 2013, WMECO issued $80 million of 3.88 percent Series G Senior Notes, due to mature in 2023. The proceeds, net of issuance costs, were used to pay short-term borrowings and for other working capital purposes.

NU parent issued $750 million of Senior Notes on May 13, 2013, consisting of $300 million of 1.45 percent Series E Senior Notes, due to mature in 2018, and $450 million of 2.80 percent Series F Senior Notes, due to mature in 2023. The proceeds, net of issuance costs, were used to repay the NU parent $250 million 5.65 percent Series C Senior Notes that matured on June 1, 2013 and the NU parent $300 million floating rate Series D Senior Notes that matured on September 20, 2013. The remaining net proceeds were used to repay commercial paper program borrowings and for working capital purposes.

Yankee Gas issued $100 million of 4.82 percent Series L First Mortgage Bonds on January 2, 2014, due to mature in 2044. The proceeds, net of issuance costs, were used to repay the $75 million 4.80 percent Series G First Mortgage Bonds that matured on January 1, 2014 and to pay $25 million in short-term borrowings.

On July 31, 2013, the FERC granted authorization allowing CL&P and WMECO to incur total short-term borrowings up to a maximum of $600 million and $300 million, respectively, effective January 1, 2014 through December 31, 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 December 23, 2013, the DPU authorized NSTAR Electric to issue up to $800 million in long-term debt for the two-year period ending December 31, 2015. On September 26, 2013, the NHPUC issued an order, effective October 8, 2013, approving PSNH's request to issue up to $315 million in long-term debt through December 31, 2014, and to refinance approximately $89 million Series B PCRBs through its existing maturity of May 2021.

On September 6, 2013, NU parent, CL&P, PSNH, WMECO, NSTAR Gas and Yankee Gas amended their joint five-year $1.15 billion revolving credit facility, dated July 25, 2012, by increasing the aggregate principal amount available thereunder by $300 million to $1.45 billion, extending the expiration date from July 25, 2017 to September 6, 2018, and increasing CL&P's borrowing sub-limit from $300 million to $600 million. PSNH and WMECO each have borrowing sub-limits of $300 million. Simultaneously, effective September 6, 2013, the CL&P $300 million revolving credit facility was terminated.

On September 6, 2013, NSTAR Electric amended its five-year $450 million revolving credit facility, dated July 25, 2012, by extending the expiration date from July 25, 2017 to September 6, 2018.

On September 6, 2013, NU parent s $1.15 billion commercial paper program was increased by $300 million to $1.45 billion.

As of December 31, 2013, NU had approximately $1.01 billion in short-term borrowings outstanding under its commercial paper program, leaving $435.5 million of available borrowing capacity. The weighted-average interest rate on these borrowings as of December 31, 2013 was 0.24 percent, which is generally based on money market rates. As of December 31, 2013, NSTAR Electric had $103.5 million in short-term borrowings outstanding under its commercial paper program, leaving $346.5 million of available borrowing capacity. The weighted-average interest rate on these borrowings as of December 31, 2013 was 0.13 percent, which is generally based on money market rates.

Each of NU, CL&P, NSTAR Electric, PSNH and WMECO use its available capital resources to fund its respective construction expenditures, meet debt requirements, pay operating 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 recover its electric and natural gas distribution construction expenditures as the related project costs are depreciated over the life of the assets. 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 current liabilities exceeding current assets by approximately $1.2 billion, $398 million and $339 million at NU, CL&P and NSTAR Electric, respectively, as of December 31, 2013.

As of December 31, 2013, $501.7 million of NU's obligations classified as current liabilities relates to long-term debt that will be paid in the next 12 months, consisting of $150 million for CL&P, $301.7 million for NSTAR Electric and $50 million for PSNH. In addition, $31.7 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, PSNH and WMECO will reduce their short-term borrowings with cash received from operating cash flows or with the issuance of new long-term debt, determined considering capital requirements and maintenance of NU's credit rating and profile. Management expects the future operating cash flows of NU, CL&P, NSTAR Electric, PSNH and WMECO, along with the access to financial markets, will be sufficient to meet any future operating requirements and capital investment forecasted opportunities.

On March 15, 2013, NSTAR Electric made its final principal and interest payment on approximately $675 million of RRBs that were issued in March 2005. On May 1, 2013, PSNH made its final principal and interest payment on approximately $525 million of RRBs that were issued in April 2001. On June 1, 2013, WMECO made its final principal and interest payment on approximately $155 million of RRBs that were issued in May 2001. As a result, NSTAR Electric, PSNH and WMECO are no longer recovering any payments from customers associated with these RRBs, which reduced NSTAR Electric s, PSNH s and WMECO s cash flows provided by operating activities in 2013, compared with 2012. There was no impact on operating cash flows net of RRB payments.

Cash flows provided by operating activities totaled $1.58 billion in 2013, compared with $1.05 billion in 2012 and $901.1 million in 2011 (all amounts are net of RRB payments, which are included in financing activities on the accompanying statements of cash flows). The improved operating cash flows were due primarily to the addition of NSTAR, which contributed $138.1 million of operating cash flows (net of RRB payments) in the first quarter of 2013, a decrease of approximately $100 million in cash disbursements for storm restoration costs associated primarily with the February 2013 blizzard, as compared to 2012 cash disbursements for storm restoration costs associated primarily with Tropical Storm Irene and the October 2011 snowstorm, the absence in 2013 of $73 million in 2012 cash disbursements at CL&P, NSTAR Electric, NSTAR Gas and WMECO related to customer bill credits, and the absence in 2013 of $35 million of merger-related cash payments made in 2012. In addition, operating cash flows benefited from an increase in amortization of regulatory deferrals primarily attributable to tracking mechanisms where such revenues exceeded costs resulting in a favorable cash flow impact. Partially offsetting these favorable cash flow impacts was a $62.3 million increase in Pension Plan cash contributions, increases in coal and fuel inventories, and changes in traditional working capital amounts due primarily to the timing of accounts receivable and accounts payable. The improved operating cash flows in 2012, compared with 2011, were due primarily to the addition of NSTAR, partially offset by an increase in storm restoration costs, pension plan cash contributions, customer bill credits, and merger-related costs.

A summary of our corporate credit ratings and outlooks by Moody's, S&P and Fitch is as follows:

	Moody's		**S&P**		**Fitch**	
	Current	**Outlook**	**Current**	**Outlook**	**Current**	**Outlook**
NU Parent	Baa1	Stable	A-	Stable	BBB+	Stable
CL&P	Baa1	Stable	A-	Stable	BBB+	Stable
NSTAR Electric	A2	Stable	A-	Stable	A	Stable
PSNH	Baa1	Stable	A-	Stable	BBB+	Stable
WMECO	A3	Stable	A-	Stable	BBB+	Stable

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	Baa1	Stable	BBB+	Stable	BBB+	Stable
CL&P	A2	Stable	A	Stable	A	Stable
NSTAR Electric	A2	Stable	A-	Stable	A+	Stable
PSNH	A2	Stable	A	Stable	A	Stable
WMECO	A3	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. On January 31, 2014, Moody's upgraded corporate credit and securities ratings of NU, CL&P and PSNH by one level and WMECO by two-levels.

We paid common dividends of $462.7 million in 2013, compared with $375 million in 2012. The increase was due primarily to the issuance of approximately 136 million of NU common shares to the NSTAR shareholders on April 10, 2012 as a result of the merger, and an increase of approximately 7.1 percent in our common dividend paid beginning in March 2013. On February 4, 2014, our Board of Trustees approved a common dividend payment of $0.3925 per share, payable on March 31, 2014 to shareholders of record as of March 3, 2014. The dividend represented an increase of 6.8 percent over the dividend paid in December 2013.

CL&P, NSTAR Electric, PSNH, and WMECO paid $152 million, $56 million, $68 million, and $40 million, respectively, in common dividends to their respective parent company in 2013.

Investments in Property, Plant and Equipment on the accompanying statements of cash flows do not include amounts incurred on capital projects but not yet paid, cost of removal, AFUDC related to equity funds, and, for certain subsidiaries, the capitalized portions of pension expense. In 2013, investments for NU, CL&P, NSTAR Electric, PSNH, and WMECO were $1.5 billion, $434.9 million, $476.6 million, $186 million, and $128.8 million, respectively.

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 expense (all of which are non-cash factors), totaled $1.6 billion in 2013, $1.5 billion in 2012, and $1.2 billion in 2011. These amounts included $44.7 million in 2013, $43.1 million in 2012, and $51.9 million in 2011, related to our corporate service companies, NUSCO and RRR.

Transmission Business: Overall, transmission business capital expenditures increased by $10.5 million in 2013, as compared with 2012, due primarily to the addition of NSTAR Electric's capital expenditures, partially offset by the completion of the WMECO portion of GSRP. A summary of transmission capital expenditures by company in 2013, 2012 and 2011 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2013**	**2012** [(1)]	**2011**
CL&P	$ 211.9	$ 182.5	$ 128.6
NSTAR Electric	220.8	160.7	N/A
PSNH	99.7	55.7	68.1
WMECO	87.2	214.7	236.8
NPT	39.9	35.4	25.9
Total Transmission Segment	$ 659.5	$ 649.0	$ 459.4

(1)

Results include the transmission capital expenditures of NSTAR Electric beginning April 10, 2012.

NEEWS: GSRP, the first, largest and most complicated project within the NEEWS family of projects was fully energized on November 20, 2013. The project involved the construction of 115 kV and 345 kV overhead lines by CL&P and WMECO from Ludlow, Massachusetts to Bloomfield, Connecticut. This transmission upgrade ensures the reliable flow of power in and around the southern New England area and enables access to less expensive generation, further reducing the risk of congestion costs impacting New England customers. The project was fully energized ahead of schedule with a final cost of $676 million, $42 million under the $718 million estimated cost. As of December 31, 2013, CL&P and WMECO have placed $628.2 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 the second major NEEWS project. All siting applications have been filed by CL&P and National Grid. The Connecticut and Rhode Island portions of the project have been approved and a siting approval decision in Massachusetts is expected in early 2014. On February 12, 2014, the Army Corps of Engineers issued its permit enabling construction on the Connecticut portion of the project. This is the final permit for the Connecticut portion of the project. NU s portion of the cost is estimated to be

$218 million and the project is expected to be placed in service in late 2015.

The Greater Hartford Central Connecticut Study (GHCC), which includes the reassessment of the Central Connecticut Reliability Project, continues to make progress. The final need results, which were presented to the ISO-NE Planning Advisory Committee in November 2013, showed existing and worsening severe regional and local thermal overloads and voltage violations within and across each of the four study areas. ISO-NE is expected to confirm the preferred transmission solutions in the first half of 2014, which are likely to include many 115 kV upgrades. We continue to expect that the specific future projects being identified to address these reliability concerns will cost approximately $300 million and that the project will be placed in service in 2017.

Included as part of NEEWS are associated reliability related projects, $90.8 million of which have been placed in service. As of December 31, 2013, the remaining construction on the associated reliability related projects totaled $2.8 million, which is scheduled to be completed by mid-2014.

Through December 31, 2013, CL&P and WMECO capitalized $252.8 million and $567 million, respectively, in costs associated with NEEWS, of which $40.8 million and $48.9 million, respectively, were capitalized in 2013.

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 crosses the Cape Cod Canal and associated 115 kV upgrades in the center of Cape Cod (Lower SEMA Project) and related 115 kV projects (Mid-Cape Project). The Lower SEMA Project line work was completed and placed into service in 2013. The Mid-Cape Project is scheduled to be completed in 2017. The aggregate estimated construction cost for the Cape Cod projects is expected to be approximately $150 million. Through December 31, 2013, NSTAR Electric has invested $96 million in costs associated with the Cape Cod Reliability Projects, of which $61 million was capitalized in 2013.

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. The $1.4 billion project is subject to comprehensive federal and state public permitting processes and is expected to be operational by mid-2017. On July 1, 2013, NPT filed an amendment to the DOE Presidential Permit Application for a proposed improved route in the northernmost section of the project area. As of December 31, 2013, the DOE had completed its public scoping meeting process and the majority of its seasonal field work and environmental data collection. NPT expects to file its state permit application in the fourth quarter of 2014 after the DOE s draft Environmental Impact Statement (EIS) is received.

NPT filed an amendment to the Transmission Services Agreement (TSA) with FERC on December 11, 2013, which was accepted by the FERC on January 13, 2014. The TSA amendment that went into effect on February 14, 2014 extended certain deadlines to provide project flexibility and eliminated a penalty payment for termination of the project in the future.

On December 31, 2013, NPT received ISO-NE approval under Section I.3.9 of the ISO tariff. By approving the project s Section I.3.9 application, ISO-NE determined that Northern Pass can reliably interconnect with the New England grid with no significant, adverse effect on the reliability or operating characteristics of the regional energy grid and its participants.

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 expect projected costs to be approximately $440 million on these new initiatives.

Distribution Business: A summary of distribution capital expenditures by company for 2013, 2012 and 2011 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars)		**2013**		**2012** [(1)]		**2011**
CL&P:						
Basic Business	$	60.9	$	69.2	$	166.6
Aging Infrastructure		160.7		177.8		112.3
Load Growth		76.9		65.8		59.6
Total CL&P		298.5		312.8		338.5
NSTAR Electric:						
Basic Business		98.5		47.3		N/A
Aging Infrastructure		110.6		111.5		N/A
Load Growth		53.6		17.4		N/A
Total NSTAR Electric		262.7		176.2		N/A
PSNH:						
Basic Business		22.7		25.3		47.7
Aging Infrastructure		50.5		50.2		25.3
Load Growth		29.3		20.2		25.8
Total PSNH		102.5		95.7		98.8
WMECO:						
Basic Business		7.9		12.7		24.2
Aging Infrastructure		24.6		18.5		11.5
Load Growth		9.2		6.5		6.1
Total WMECO		41.7		37.7		41.8
		705.4		622.4		479.1

Total - Electric Distribution (excluding Generation)						
Total - Natural Gas		175.2		162.9		102.8
Other Distribution		0.7		0.1		1.0
Total Electric and Natural Gas		881.3		785.4		582.9
PSNH Generation:						
Clean Air Project		-		22.0		101.1
Other		9.7		7.9		23.7
Total PSNH Generation		9.7		29.9		124.8
WMECO Generation		4.5		0.7		11.7
Total Distribution Segment	$	895.5	$	816.0	$	719.4

(1)

Results include the electric and natural gas distribution capital expenditures of NSTAR beginning April 10, 2012.

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

CL&P System Resiliency Plan: In accordance with the PURA-approved System Resiliency Plan, CL&P will spend approximately $300 million to improve the resiliency of its electric distribution system, which includes vegetation management. CL&P expects to complete the plan in five years in two separate phases. Costs of Phase 1 of the plan, which is primarily focused on vegetation management, totaled approximately $32 million in 2013 and is estimated to cost $53 million in 2014. Phase 2 of the plan is estimated to cost approximately $215 million over the period from 2015 through 2017.

WMECO Solar Project: On September 4, 2013, the DPU approved WMECO's proposal to build a third solar generation facility and expand its solar energy portfolio from 6 MW to 8 MW. On October 22, 2013, WMECO announced it would install a 3.9 MW solar generation facility on a site in East Springfield, Massachusetts. The facility is expected to be completed in mid-2014 at an estimated cost of approximately $15 million.

40

Yankee Gas Expansion Plan: In accordance with 2013 Connecticut law and regulation, on June 14, 2013, Yankee Gas and other Connecticut natural gas distribution companies filed a comprehensive joint natural gas infrastructure expansion plan (expansion plan) with DEEP and PURA. The expansion plan described how Yankee Gas expects to add approximately 82,000 new natural gas heating customers over the next 10 years. Yankee Gas estimates that its portion of the plan will cost approximately $700 million over 10 years. For further information on the expansion plan, see "Regulatory Developments and Rate Matters - Connecticut - Yankee Gas Natural Gas Expansion Plan" in this *Management s Discussion and Analysis.* For further information on the Connecticut law, see "Legislative and Policy Matters - Connecticut" in this *Management s Discussion and Analysis.*

Projected Capital Expenditures: A summary of the projected capital expenditures for the Regulated companies' electric transmission and for the total electric distribution, generation, and natural gas distribution businesses for 2014 through 2017, including our corporate service companies' capital expenditures on behalf of the Regulated companies, is as follows:

	Year				
(Millions of Dollars)	**2014**	**2015**	**2016**	**2017**	**2014-2017 Total**
CL&P Transmission	$ 247	$ 199	$ 178	$ 165	$ 789
NSTAR Electric Transmission	191	250	285	202	928
PSNH Transmission	106	124	123	42	395
WMECO Transmission	73	85	49	2	209
NPT	47	222	610	487	1,366
Total Transmission	$ 664	$ 880	$ 1,245	$ 898	$ 3,687
Electric Distribution	$ 679	$ 647	$ 647	$ 619	$ 2,592
Generation	24	34	20	15	93
Natural Gas	189	219	201	227	836
Total Distribution	$ 892	$ 900	$ 868	$ 861	$ 3,521
Corporate Service Companies	$ 117	$ 93	$ 76	$ 76	$ 362
Total	$ 1,673	$ 1,873	$ 2,189	$ 1,835	$ 7,570

Actual capital expenditures could vary from the projected amounts for the companies and years 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 NETOs, 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 October 1, 2011. In response, the NETOs filed testimony and analysis based on standard FERC methodology and precedent demonstrating that the base ROE of 11.14 percent remained just and reasonable. The FERC set the case for trial before a FERC ALJ after settlement negotiations were unsuccessful in August 2012.

Hearings before the FERC ALJ were held in May 2013, followed by the filing of briefs by the complainants, the Massachusetts municipal electric utilities (late interveners to the case), the FERC trial staff and the NETOs. The NETOs recommended that the current base ROE of 11.14 percent should remain in effect for the refund period (October 1, 2011 through December 31, 2012) and the prospective period (beginning when FERC issues its final decision). The complainants, the Massachusetts municipal electric utilities, and the FERC trial staff each recommended a base ROE of 9 percent or below.

On August 6, 2013, the FERC ALJ issued an initial decision, finding that the base ROE in effect from October 2011 through December 2012 was not reasonable under the standard application of FERC methodology, but leaving policy considerations and additional adjustments to the FERC. Using the established FERC methodology, the FERC ALJ determined that separate base ROEs should be set for the refund period and the prospective period. The FERC ALJ found those base ROEs to be 10.6 percent and 9.7 percent, respectively. The FERC may adjust the prospective period base ROE in its final decision to reflect movement in 10-year Treasury bond rates from the date that the case was filed (April 2013) to the date of the final decision. The parties filed briefs on this decision with the FERC, and a decision from the FERC is expected in 2014. Though NU cannot predict the ultimate outcome of this proceeding, in 2013 the Company recorded a series of reserves at its electric subsidiaries to recognize the potential financial impact from the FERC ALJ's initial decision for the refund period. The aggregate after-tax charge to earnings totaled $14.3 million at NU, which represents reserves of $7.7 million at CL&P, $3.4 million at NSTAR Electric, $1.4 million at PSNH and $1.8 million at WMECO.

On December 27, 2012, several additional parties filed a separate complaint concerning the NETOs' base ROE with the FERC. This complaint seeks to reduce the NETOs base ROE effective January 1, 2013, effectively extending the refund period for an additional 15 months, and to consolidate this complaint with the joint complaint filed on September 30, 2011. The NETOs have asked the FERC to reject this complaint. The FERC has not yet acted on this complaint, and management is unable to predict the ultimate outcome or estimate the impacts of this complaint on the financial position, results of operations or cash flows.

As of December 31, 2013, the CL&P, NSTAR Electric, PSNH, and WMECO aggregate shareholder equity invested in their transmission facilities was approximately $2.3 billion. As a result, each 10 basis point change in the prospective period authorized base ROE would change annual consolidated earnings by an approximate $2.3 million.

Regulatory Developments and Rate Matters

Electric and Natural Gas Base Distribution Rates:

Each NU utility subsidiary is subject to the regulatory jurisdiction of the state in which it operates: CL&P and Yankee Gas operate in Connecticut and are subject to PURA regulation; NSTAR Electric, WMECO and NSTAR Gas operate in Massachusetts and are subject to DPU regulation; and PSNH operates in New Hampshire and is subject to NHPUC regulation.

In Connecticut, pursuant to the April 2012 PURA-approved Connecticut merger settlement agreement, CL&P is subject to a base distribution rate freeze until December 1, 2014. Yankee Gas distribution rates were established in a 2011 PURA approved rate case. See *Connecticut - Yankee Gas Distribution Rate Case* in this *Regulatory Developments and Rate Matters* section for further information.

In Massachusetts, "An Act Relative to Competitively Priced Electricity in the Commonwealth" (Energy Act), which was enacted in 2012, requires electric utility companies to file at least one distribution rate case every five years and natural gas companies to file at least one distribution rate case every 10 years, and limits those companies to one settlement agreement in any 10-year period. Pursuant to the April 2012 DPU-approved Massachusetts comprehensive merger settlement agreements, NSTAR Electric, WMECO and NSTAR Gas are subject to a base distribution rate freeze through December 31, 2015.

In New Hampshire, PSNH is currently operating under the 2010 NHPUC approved distribution rate case settlement, which is effective through June 30, 2015. Under the settlement, PSNH is permitted to file a request to collect certain exogenous costs and step increases on an annual basis. See *New Hampshire - Distribution Rates* in this *Regulatory Developments and Rate Matters* section for further information.

As a result of the PURA-approved Connecticut merger settlement agreement, we expect to file a CL&P base distribution rate proceeding in mid-2014 with base distribution rates effective December 1, 2014. The exact timing of the base distribution rate proceedings for our other utility subsidiaries has not yet been determined.

Major Storms:

2013, 2012 and 2011 Major Storms: Over the past three years, CL&P, NSTAR Electric, PSNH and WMECO each experienced significant storms, including Tropical Storm Irene, the October 2011 snowstorm, Storm Sandy, and the February 2013 blizzard. As a result of these storms, each electric utility company suffered damage to its distribution and transmission systems, which caused customer outages and required the incurrence of costs to repair significant damage and restore customer service.

The magnitude of these storm restoration costs met the criteria for cost deferral in Connecticut, Massachusetts, and New Hampshire. As a result, the storms had no material impact on the results of operations of CL&P, NSTAR Electric, PSNH and WMECO. We believe our response to each of these 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 electric utility company is seeking recovery of its deferred storm restoration costs through its applicable regulatory recovery process.

CL&P 2013 Storm Filing: In March 2013, CL&P filed a request with PURA for approval to recover storm restoration costs associated with five major storms, all of which occurred in 2011 and 2012. CL&P's deferred storm restoration costs associated with these major storms totaled $462 million. Of that amount, approximately $414 million is subject to recovery in rates after giving effect to CL&P s agreement to forego the recovery of $40 million of previously deferred storm restoration costs as well as an existing storm reserve fund balance of approximately $8 million. During the second half of 2013, the PURA proceeded with the storm recovery review issuing discovery, holding hearings and ultimately on February 3, 2014, issuing a draft decision on the level of storm costs recovery.

In its draft decision, the PURA approved recovery of $365 million of deferred storm restoration costs and ordered CL&P to capitalize approximately $18 million of the deferred storm restoration costs as utility plant, which will be included in depreciation expense in future rate proceedings. PURA will allow recovery of the $365 million with carrying charges in CL&P s distribution rates over a six-year period beginning December 1, 2014. The remaining costs were either disallowed or are probable of recovery in future rates and did not have a material impact on CL&P s financial position, results of operations or cash flows. The final decision is expected from PURA in the first quarter of 2014.

NSTAR Electric 2013 Storm Filing: On December 30, 2013, the DPU approved NSTAR Electric s request to recover storm restoration costs, plus carrying costs, related to Tropical Storm Irene and the October 2011 snowstorm. The DPU approved recovery of $34.2 million of the $38 million requested costs. NSTAR Electric will recover these costs, plus carrying costs, in its distribution rates over a five-year period that commenced on January 1, 2014.

PSNH Major Storm Cost Reserve: On June 27, 2013, the NHPUC approved an increase to PSNH s distribution rates effective July 1, 2013 that included a $5 million increase to the current level of funding for the major storm cost reserve.

WMECO SRRCA Mechanism: WMECO has an established Storm Reserve Recovery Cost Adjustment (SRRCA) mechanism to recover the restoration costs associated with its major storms. Effective January 1, 2012, WMECO began recovering the restoration costs of Tropical Storm Irene and other storms that took place prior to August 2011. On August 30, 2013, WMECO submitted its 2013 Annual SRRCA filing to begin recovering the restoration costs associated with the October 2011 snowstorm and Storm Sandy. On

December 20, 2013, the DPU approved the 2013 Annual SRRCA filing for effect on January 1, 2014, subject to further review and reconciliation.

2013, 2012 and 2011 Major Storm Deferrals: As of December 31, 2013, the storm restoration costs deferred for recovery from customers for major storms that occurred during 2013, 2012 and 2011 at CL&P, NSTAR Electric, PSNH, and WMECO were as follows:

(Millions of Dollars)	**2012 and 2011**	**2013**	**Total**
CL&P	$ 365.0	$ 28.8	$ 393.8
NSTAR Electric	61.3	63.6	124.9
PSNH	33.7	5.3	39.0
WMECO	35.3	-	35.3
Total	$ 495.3	$ 97.7	$ 593.0

DPU Storm Penalties: Under Massachusetts law and regulation, the DPU has established standards of performance for emergency preparation and restoration of service for electric companies, including required annual ERP filings with the DPU for review and approval. As a remedy to violations of those standards, the DPU is authorized to levy a penalty not to exceed $250,000 for each violation for each day that the violation persists up to a maximum penalty of $20 million for any related series of violations. In December 2012, in separate orders issued by the DPU, NSTAR Electric and WMECO each received penalties related to 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, which were refunded to their customers. In December 2012, NSTAR Electric and WMECO each filed appeals with the SJC arguing the DPU penalties should be vacated. NSTAR Electric and WMECO filed initial briefs on November 5, 2013. Oral arguments are scheduled for March 2014.

Emergency Response Plans: Under Connecticut law and regulation, the PURA has established performance standards that electric and natural gas companies incorporated into their ERPs and operations in 2013. CL&P and Yankee Gas will be subject to penalties levied by PURA of up to 2.5 percent of annual distribution revenues for failure to meet performance standards. In 2013, CL&P and Yankee Gas met the established performance standards.

Connecticut:

CL&P 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, 2014, the PURA approved an increase to CL&P s energy supply portion of the total average SS rate from 7.638 cents per kWh to 9.152 cents per kWh and the energy supply portion of the total average LRS rate from 6.698 cents per kWh to 10.762 cents per kWh. These changes were due primarily to the market conditions for the procurement of energy. The SS and LRS rates reflect CL&P s costs to procure energy for its customers. Adjustments to these rates do not impact earnings as CL&P is fully recovering the costs of its SS and LRS services from customers.

<u>CL&P CTA and SBC Reconciliation</u>: On January 22, 2014, PURA approved CL&P s 2012 CTA and SBC reconciliation as filed on April 1, 2013, which compared CTA and SBC billed revenues to revenue requirements, as required by PURA. The 2012 CTA was over recovered by $21.3 million, resulting in a cumulative net under recovered balance of $8.9 million as of December 31, 2012. The 2012 SBC was over recovered by $19.4 million, resulting in a cumulative net under recovery of $19.7 million as of December 31, 2012.

<u>CL&P FMCC Filing</u>: 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 August 1, 2013, CL&P filed with PURA its semi-annual FMCC filing for the period January 1, 2013 through June 30, 2013. This filing also included the June 30, 2013 through December 31, 2013 projected amounts for informational purposes only. The filing identified a total net under recovery of $2.7 million for the period. On February 19, 2014, PURA approved CL&P s FMCC filing.

<u>CL&P Conservation Adjustment Mechanism</u>: In 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 those already collected through the statutory charge and the revenues lost because of the expanded energy efficiency programs. On September 11, 2013, DEEP approved CL&P s expanded 2014 conservation spending budget of $144.6 million. The PURA approved a CAM effective January 1, 2014 subject to a future review of its revenue and expense reconciliation filing to be submitted by CL&P.

<u>CL&P Long-Term Wind Contracts</u>: On September 19, 2013, CL&P, along with another Connecticut utility, signed long-term commitments, as required by regulation, to purchase approximately 250 MW of wind power from a Maine wind farm and 20 MW of solar power from sites in Connecticut, at a combined average price of less than 8 cents per kWh. On October 23, 2013, PURA issued a final decision accepting the contracts. The projects are expected to be operational by the end of 2016. For further information, see "Legislative and Policy Matters - Connecticut" in this *Management s Discussion and Analysis*.

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

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

Yankee Gas Natural Gas Expansion Plan: On June 14, 2013, Yankee Gas and other Connecticut natural gas distribution companies filed an expansion plan with DEEP and PURA in response to the Connecticut CES and the recently enacted Connecticut Public Act 13-298, "An Act Concerning Implementation of Connecticut s Comprehensive Energy Strategy and Various Revisions to the Energy Statutes." The expansion plan describes how the natural gas distribution companies expect to add approximately 280,000 new natural gas heating customers over the next 10 years. Yankee Gas will serve approximately 82,000 of those customers.

The expansion plan outlines a set of comprehensive recommendations, several of which are already incorporated into Public Act 13-298. Key recommendations include providing more flexibility in the process of adding new customers, establishing new regulatory tools to help fund conversion costs over time, providing for mechanisms for timely recovery of capital investments made by natural gas distribution companies and allowing utilities to secure additional pipeline capacity into Connecticut.

On July 16, 2013, DEEP issued a determination letter finding the expansion plan was consistent with the CES and requesting certain modifications to be made. On July 26, 2013, the natural gas distribution companies submitted their responses to DEEP and PURA. On November 22, 2013, PURA issued a final decision approving the expansion plan consistent with the goals of the CES. For further information on the Connecticut law, see "Legislative and Policy Matters - Connecticut" in this *Management s Discussion and Analysis.*

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). NSTAR Electric and WMECO fully recover their energy costs through DPU-approved regulatory rate mechanisms.

2014 Annual Reconciliation Filing: On November 1, 2013, NSTAR Electric and WMECO filed separately their respective 2014 annual cost recovery mechanisms, including the mechanisms to collect the costs to provide retail transmission, energy supply and energy efficiency services to its customers as well as the costs related to pension and other post-retirement employee benefit costs. The reconciliation filings compared the total revenues to revenue requirements related to these services. On December 31, 2013, the DPU issued a final decision approving the rates as filed, subject to future review and reconciliation. As of December 31, 2013, we had cumulative deferred net regulatory asset balances related to these services of $142.1 million and $9.9 million for NSTAR Electric and WMECO, respectively.

Energy Efficiency Plans: In accordance with Massachusetts law passed in 2008 known as the Green Communities Act, natural gas and electric distribution companies must file three-year energy efficiency plans, which were initially filed by NSTAR Electric, WMECO and NSTAR Gas, and approved by the DPU, in 2010 covering the period 2010 through 2012. The NSTAR Electric, WMECO and NSTAR Gas three-year plans covering the period 2013 through 2015 were approved by the DPU in 2013. Distribution companies that do not yet have rate decoupling mechanisms in place, like NSTAR Electric and NSTAR Gas, include Lost Base Revenue (LBR) rate adjustment mechanisms in order to offset reduced distribution rate revenues as a result of successful energy efficiency programs. For the year ended December 31, 2013, NSTAR Electric, WMECO and NSTAR Gas incurred recoverable Energy Efficiency program expenses of $167.2 million, $38.9 million, and $31 million, respectively.

Long-Term Wind Contracts: NSTAR Electric and WMECO, along with two other Massachusetts utilities, signed a long-term commitment, as required by regulation, to purchase wind power from six wind farms in Maine and New Hampshire for a combined estimated generating capacity of approximately 565 MW. On September 20, 2013, these contracts were filed jointly with the DPU. On November 21, 2013, the utility companies provided a supplemental filing to the DPU to reflect the termination of three of the six wind farms. Initial briefs were filed on December 23, 2013 and reply briefs were filed on January 8, 2014. Over the 15-year life of the remaining contracts, the utilities will pay an average price of less than 8 cents per kWh. The projects are in various stages of permitting or development and are expected to begin operation in 2015 and 2016.

On November 26, 2012, the DPU approved NSTAR Electric s 15-year renewable energy contract with Cape Wind Associates, LLC. Under this contract, NSTAR Electric would purchase 129 MW of renewable energy from an offshore wind energy facility, which is currently expected to achieve commercial operation by May 2016.

DPU Safety and Reliability Programs (CPSL): Since 2006, NSTAR Electric has been recovering incremental costs related to the DPU-approved Safety and Reliability Programs. From 2006 through 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). In October 2010, NSTAR Electric filed a reconciliation of the cumulative CPSL program activity for the periods 2006 through 2009 with the DPU in order to determine a proposed rate adjustment. The DPU allowed the proposed rates to go into effect January 1, 2011, subject to final

reconciliation of CPSL program costs through a future DPU proceeding. In February 2013, NSTAR Electric updated the October 2010 filing with final activity through 2011. NSTAR Electric recorded its 2006 through 2011 revenues under the CPSL programs based on the May 2010 Order.

NSTAR Electric cannot predict the timing of a final DPU order related to its CPSL filings for the period 2006 through 2011. While we do not believe that any subsequent DPU order would result in revenues that are 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 stipulates that NSTAR Electric must incur a revenue requirement of at least $15 million per year for 2012 through 2015 related to 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, 2013, NSTAR Electric was in compliance with the performance metrics and has recognized the entire $15 million revenue requirement during 2013 and 2012.

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. In 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. The DPU issued an order approving the implementation of a revised Basic Service rate but 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.

In 2010, NSTAR Electric filed an appeal of the DPU s order with the SJC. In 2012, the SJC vacated the DPU order and remanded the matter to the DPU for further review. The DPU has not taken any action on the remand.

NSTAR Electric deferred approximately $34 million of costs associated with energy-related bad debt as a regulatory asset through 2011 as NSTAR Electric had concluded that it was probable that these costs would ultimately be recovered from customers. Due to delays and the duration of the proceedings, 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 related to the regulatory asset in 2012. NSTAR Electric will continue to maintain the reserve until the proceeding has been concluded with the DPU.

New Hampshire:

Distribution Rates: In 2013, PSNH filed for a distribution rate step increase in accordance with the 2010 NHPUC approved distribution rate case settlement. On June 27, 2013, the NHPUC approved an increase to rates of $12.6 million, effective July 1, 2013. The increase consists primarily of $7.7 million related to net plant additions and a $5 million increase to the current level of funding for the Major Storm Cost reserve.

ES and SCRC Rates: On December 12, 2013, PSNH filed a request with the NHPUC to adjust its ES and SCRC rates effective January 1, 2014. PSNH s request proposed to increase the current ES and SCRC billing rates to reflect projected costs for 2014. On December 27, 2013, the NHPUC approved the request. The approved energy supply portion of the 2014 rate is 9.23 cents per kWh and the SCRC rate for 2014 is 0.35 cents per kWh.

Clean Air Project Prudence Proceeding: The Clean Air Project, which involved the installation of wet scrubber technology at PSNH s Merrimack coal-fired generation station in Bow, New Hampshire, was placed in service in September 2011. In November 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. In April 2012, the NHPUC issued an order authorizing temporary rates to recover a significant portion of the Clean Air Project costs. The docket will remain open to conduct a comprehensive prudence review of the Clean Air Project and the establishment of permanent rates. The temporary rates will remain in effect until permanent rates allowing full recovery of all prudently incurred costs are approved. At that time, the NHPUC will reconcile recoveries collected under the temporary rates with approved permanent rates.

The NHPUC has issued a series of orders ruling on the scope of its Clean Air Project inquiry and discovery issues. On December 23, 2013, the NHPUC Staff and other intervenors filed testimony discussing the prudency of the Clean Air Project, which cost $421 million. Discovery is currently ongoing with hearings likely in late 2014. We continue to believe that we were prudent in the undertaking and completion of the Clean Air Project. While we cannot predict with certainty the outcome of the Clean Air Project prudence review, we believe all costs were incurred appropriately and are probable of recovery.

PSNH Generation: On January 18, 2013, the NHPUC opened a docket to investigate market conditions affecting PSNH s ES 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. On July 15, 2013, the NHPUC accepted from the NHPUC Staff a "Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impact on the Competitive Electricity Market." The report recommended that the NHPUC examine whether default service rates remain sustainable on a going forward basis, define "just and reasonable" with respect to default service in the context of competitive retail markets, analyze the current and expected value of PSNH s generating units, and identify means to mitigate and address stranded cost recovery.

On September 18, 2013, the NHPUC issued a Request for Proposal to hire a valuation expert to determine the value of PSNH's generation assets and entitlements. On October 16, 2013, the State of New Hampshire Legislative Oversight Committee on Electric Utility Restructuring (Oversight Committee) requested that the NHPUC conduct an analysis to determine whether it is now in the economic interest of PSNH s retail customers for PSNH to divest its interest in generation plants. On November 1, 2013, the Oversight Committee asked for a preliminary report on the findings by April 1, 2014 that would include at a minimum the NHPUC Staff s position, the analysis of the valuation expert, and any recommendations for legislation that may be needed concerning divestiture or otherwise related to this issue. A valuation expert has been hired and the investigation is currently ongoing. At this time, we cannot predict the outcome of this review. Our current PSNH generation rate base totals approximately $760 million. We continue to believe all costs and generation investments are probable of recovery.

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 that closed-cycle cooling systems are not warranted.

Legislative and Policy Matters

Federal:

On January 2, 2013, the "American Taxpayer Relief Act of 2012" became law, which extended the accelerated deduction of depreciation to businesses through 2013. This extended stimulus provided NU with cash flow benefits of approximately $300 million (approximately $95 million at CL&P, $85 million at NSTAR Electric, $35 million at PSNH, and $50 million at WMECO).

On September 13, 2013, the Internal Revenue Service issued final Tangible Property regulations that are meant to simplify, clarify and make more administrable previously issued guidance. In the third quarter of 2013, CL&P recorded an after-tax valuation allowance of $10.5 million against its deferred tax assets as a result of these regulations. NU is in compliance with the new regulations, but continues to evaluate several new potential elections. Therefore, a change to the valuation allowance at CL&P could result once NU completes the review of the impact of the final regulations.

Connecticut:

In 2013, Connecticut enacted into law two significant energy bills. The first law, Public Act 13-298, implemented a number of the recommendations proposed in the CES. Public Act 13-298 authorized the filing of a plan to expand natural gas service to Connecticut residents that currently do not have access to natural gas. For further information on Yankee Gas filing, see "Regulatory Developments and Rate Matters - Connecticut - Yankee Gas Natural Gas Expansion Plan" in this *Management's Discussion and Analysis.* The law also required PURA to implement decoupling for each of Connecticut s electric and natural gas utilities in their next respective rate cases. Finally, the law allows electric distribution companies to recover their costs as well as lost revenues from various state energy policy initiatives, including expanded energy efficiency programs.

The second law, Public Act 13-303, "An Act Concerning Connecticut s Clean Energy Goals," allows DEEP to conduct a process to procure from renewable energy generators, under long-term contracts with the electric distribution companies, additional renewable generation to help Connecticut meet its Renewable Portfolio Standard (RPS). Large scale hydropower facilities located in the New England Power Pool Generation Information System (NEPOOL GIS) geographic eligibility area or an area abutting the northern boundary of the NEPOOL GIS geographic eligibility area are eligible to bid into DEEP's process. If Connecticut experiences a material shortfall in reaching its RPS goals, such hydropower, under certain conditions, can be used to alleviate such shortfall, up to five percent of RPS requirements in 2020.

The law also requires DEEP to develop a schedule to assign a gradually reducing renewable energy credit value for all Class I biomass or landfill generation facilities. Such reduced credit values will not apply to biogas or anaerobic digestion facilities, or to facilities that have a long-term contract in place. The commissioner of DEEP may adjust such changes to the values of renewable energy credits, if such adjustment is appropriate given the availability of other Class I renewable energy sources.

On September 26, 2013, DEEP issued a final determination that authorized the state s electric distribution companies to enter into long-term power purchase agreements for a total of 270 MW of Class I renewable generation from two projects. On October 23, 2013, PURA issued a final decision accepting the contracts presented by the electric distribution companies. On October 21, 2013, DEEP

46

issued a Request for Proposal seeking proposals for energy and RECs from private developers for up to 4 percent of the state s electric distribution companies load (estimated to be between 100 MW to 150 MW) of Class I renewable energy resources for biomass, landfill gas and run off river hydropower projects from new or existing facilities.

Massachusetts:

On July 24, 2013, Massachusetts enacted a law that changed the income tax rate applicable to utility companies effective January 1, 2014, from 6.5 percent to 8 percent. The tax law change required NU to remeasure its accumulated deferred income taxes and resulted in NU increasing its deferred tax liability with an offsetting regulatory asset of approximately $61 million at its utility companies.

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 financial statements for further information concerning the accounting policies, estimates and assumptions used in the preparation of our 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 for 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 Regulatory assets are amortized as the incurred costs are recovered through 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 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 from customers 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 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 financial statements.

Pension and PBOP: NUSCO sponsors the NUSCO Pension Plan and NSTAR Electric acts as plan sponsor for the NSTAR Pension Plan, both of which cover certain of our employees. In addition, our service company sponsors the NUSCO and NSTAR 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.

47

Pre-tax net periodic benefit expense (excluding SERP) for the Pension Plans was $236.3 million, $234.9 million and $127.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. The pre-tax net periodic benefit expense for the PBOP Plans was $32.6 million, $72.3 million and $43.6 million for the years ended December 31, 2013, 2012 and 2011, respectively. NSTAR pension and PBOP expense was included in NU beginning April 10, 2012.

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

<u>Expected Long-Term Rate of Return on Plan Assets</u>: In developing this assumption, we consider historical and expected returns and input from our 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, 2013, our aggregate expected long-term rate of return assumption of 8.25 percent was used to determine our pension and PBOP expense. For the forecasted 2014 pension and PBOP expense, our expected long-term rate of return of 8.25 percent for all plans was used reflecting our target asset allocations within both the NUSCO and NSTAR Pension and PBOP Plans.

<u>Discount Rate</u>: 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 were 5.03 percent for the NUSCO Pension Plan, 4.85 percent for the NSTAR Pension Plan, 4.78 percent for the NUSCO PBOP Plans and 5.10 percent for the NSTAR PBOP Plan as of December 31, 2013.

<u>Compensation/Progression Rate</u>: This assumption reflects the expected long-term salary growth rate, which impacts the estimated benefits that pension plan participants receive in the future. As of December 31, 2013 and 2012, we used a compensation/progression rate of 3.5 percent for the NUSCO Pension Plan and 4 percent for the NSTAR Pension Plan, which reflects our current expectation of future salary increases, including consideration of the levels of increases built into collective bargaining agreements.

<u>Actuarial Determination of Expense</u>: 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 (which was fully amortized in 2013), 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, 2013, investment gains and losses that remain to be reflected in the calculation of plan assets over the next four years were losses of $41.8 million and gains of $27.6 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, 2013, the net unrecognized actuarial losses on the NUSCO Pension and PBOP Plan liabilities were $628.8 million and $111 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, 2013 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, 2013, the net unrecognized actuarial losses on the NSTAR Pension and PBOP Plan liabilities were approximately $498 million and $12.1 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 $132 million and $9.1 million, respectively, in 2014. 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. We contributed $57.6 million to the PBOP Plans in 2013 and expect to contribute $39.7 million in 2014. 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 $202.7 million in 2013, of which $108.3 million was contributed by PSNH. NSTAR Electric contributed $82 million to the NSTAR Pension Plan in 2013. 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 94.6 percent and 96 percent as of January 1, 2013 for the NUSCO Pension Plan and NSTAR Pension Plan, respectively. We currently estimate that aggregate contributions of $71.6 million to the Pension Plans will be made in 2014. 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	**2013**	**2012**	**2013**	**2012**
NU				
Lower long-term rate of return	$ 17.2	$ 15.0	$ 3.4	$ 3.1
Lower discount rate	$ 22.3	$ 22.0	$ 6.8	$ 6.7
Higher compensation increase	$ 12.4	$ 10.4	N/A	N/A
NSTAR Plans				
Lower long-term rate of return	$ 5.6	$ 4.8	$ 1.8	$ 1.7
Lower discount rate	$ 5.4	$ 6.8	$ 3.4	$ 4.1
Higher compensation increase	$ 3.8	$ 3.6	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: The health care cost trend rate assumption used to calculate the 2013 PBOP expense amounts was 7 percent for the NUSCO PBOP Plan, subsequently decreasing by 50 basis points per year to an ultimate rate of 5 percent in 2017, and 7.10 percent for the NSTAR PBOP Plan, subsequently decreasing to an ultimate rate of 4.5 percent in 2024. As of December 31, 2013, the health care cost trend rate assumption used to determine the NUSCO and NSTAR PBOP Plans year end funded status is 7 percent, subsequently decreasing to an ultimate rate of 4.5 percent in 2024. The effect of a hypothetical increase in the health care cost trend rate by one percentage point would be an increase to the service and interest cost components of PBOP Plan expense by $7.1million in 2013, with a $85.8 million impact on the postretirement benefit obligation. See Note 10A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," to the financial statements for more information.

Goodwill: We have recorded approximately $3.5 billion of goodwill associated with the previous mergers and acquisitions. NU has identified its reporting units for purposes of allocating and testing goodwill as Electric Distribution, Electric Transmission and Natural Gas Distribution. These reporting units are consistent with our operating segments underlying our reportable segments. Electric Distribution and Electric Transmission reporting units include carrying 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. As of December 31, 2013, goodwill was allocated to the reporting units as follows: $2.5 billion to Electric Distribution, $0.6 billion to Electric Transmission, and $0.4 billion to Natural Gas Distribution.

We are required to test goodwill balances for impairment at least annually by considering the fair value of the reporting units, which requires us to use estimates and judgments. 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 values of the reporting units assets and liabilities 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 test as of October 1, 2013 for the Electric Distribution, Electric Transmission and Natural Gas Distribution reporting units. This evaluation required the test of several factors that impact the fair value of the reporting units, including conditions and assumptions that affect the future cash flows of the reporting units.

The 2013 goodwill impairment test resulted in a conclusion that goodwill is not impaired and none of the reporting units is at risk of a goodwill impairment.

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 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 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 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 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 financial statements.

Other Matters

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

Contractual Obligations and Commercial Commitments: Information regarding our contractual obligations and commercial commitments as of December 31, 2013 is summarized annually through 2018 and thereafter as follows:

NU

(Millions of Dollars)	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
Long-term debt maturities (a)	$ 576.7	$ 216.7	$ 200.0	$ 745.0	$ 810.0	$ 5,031.6	$ 7,580.0
Estimated interest payments on existing debt (b)	329.1	309.9	304.1	299.6	247.3	2,124.6	3,614.6
Capital leases (c)	2.6	2.4	2.2	2.1	2.1	5.4	16.8
Operating leases (d)	20.1	18.1	15.4	12.4	8.5	22.3	96.8
Funding of pension obligations (d) (h)	71.6	188.4	173.7	127.9	36.3	-	597.9
Funding of other postretirement benefit obligations (d)	39.7	37.2	18.0	15.2	14.4	-	124.5
Estimated future annual long-term contractual costs (e)	705.4	615.6	538.1	428.7	368.1	2,385.6	5,041.5
Other purchase commitments (d) (g)	1,550.7	-	-	-	-	-	1,550.7
Total (f) (i)	$ 3,295.9	$ 1,388.3	$ 1,251.5	$ 1,630.9	$ 1,486.7	$ 9,569.5	$ 18,622.8

CL&P *(Millions of Dollars)*	2014	2015	2016	2017	2018	Thereafter	Total
Long-term debt maturities [a]	$ 150.0	$ 162.0	$ -	$ 250.0	$ 300.0	$ 1,640.3	$ 2,502.3
Estimated interest payments on existing debt [b]	127.9	118.2	115.7	111.7	93.4	953.7	1,520.6
Capital leases [c]	2.1	2.0	1.9	2.0	2.0	5.4	15.4
Operating leases [d]	4.0	3.6	2.9	1.7	1.2	4.7	18.1
Funding of pension obligations [d] [h]	-	-	0.5	10.2	5.4	-	16.1
Funding of other postretirement benefit obligations [d]	4.2	3.4	1.9	0.6	0.6	0.5	11.2
Estimated future annual long-term contractual costs [e]	256.1	249.9	247.2	191.1	176.8	872.6	1,993.7
Other purchase commitments [d] [g]	678.9	-	-	-	-	-	678.9
Total [f] [i]	$ 1,223.2	$ 539.1	$ 370.1	$ 567.3	$ 579.4	$ 3,477.2	$ 6,756.3

(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 2013 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.

(d)

Amounts are not included on our balance sheets.

(e)

Other than the net mark-to-market changes on derivative contracts held by the Regulated companies, these obligations are not included on our balance sheets.

(f)

Does not include unrecognized tax benefits as of December 31, 2013, 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 $38.1 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 2014.

(h)

These amounts represent NU's estimated minimum pension contributions to its qualified Pension Plans required under federal legislation. Contributions in 2015 through 2018 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 and other reserves ($26.7 million at NU and $13.5 million at CL&P), workers compensation and long-term disability insurance reserves ($43.3 million at NU and $21.5 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 financial statements.

RESULTS OF OPERATIONS NORTHEAST UTILITIES AND SUBSIDIARIES

The following 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, 2013, 2012, and 2011. The year ended December 31, 2012 amounts include the operations of NSTAR beginning April 10, 2012:

Comparison of 2013 to 2012:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012 [(a)]**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 7,301.2	$ 6,273.8	$ 1,027.4	16.4 %
Operating Expenses:				
Purchased Power, Fuel and Transmission	2,483.0	2,084.4	398.6	19.1
Operations and Maintenance	1,515.0	1,583.1	(68.1)	(4.3)
Depreciation	610.8	519.0	91.8	17.7
Amortization of Regulatory Assets, Net	206.3	79.8	126.5	(b)
Amortization of Rate Reduction Bonds	42.6	142.0	(99.4)	(70.0)
Energy Efficiency Programs	401.9	313.1	88.8	28.4
Taxes Other Than Income Taxes	512.2	434.2	78.0	18.0
Total Operating Expenses	5,771.8	5,155.6	616.2	12.0
Operating Income	$ 1,529.4	$ 1,118.2	$ 411.2	36.8 %

(a) The 2012 results include the operations of NSTAR beginning April 10, 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)	**2013**	**2012 [(a)]**	**Increase/ (Decrease)**	**Percent**
Electric Distribution	$ 5,362.3	$ 4,716.5	$ 645.8	13.7 %
Natural Gas Distribution	855.8	572.9	282.9	49.4
Total Distribution	6,218.1	5,289.4	928.7	17.6
Transmission	978.7	861.5	117.2	13.6
Total Regulated Companies	7,196.8	6,150.9	1,045.9	17.0
Other and Eliminations	104.4	122.9	(18.5)	(15.1)
Total Operating Revenues	$ 7,301.2	$ 6,273.8	$ 1,027.4	16.4 %

(a)

The 2012 results include the operations of NSTAR beginning April 10, 2012.

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

	For the Years Ended December 31,			
	2013	2012 [(a)]	Increase	Percent
Retail Electric Sales in GWh	55,331	54,808	523	1.0 %
Firm Natural Gas Sales in Million Cubic Feet	98,258	87,527	10,731	12.3 %

(a)

Results include retail electric sales of NSTAR Electric and the firm natural gas sales of NSTAR Gas from January 1, 2012 through December 31, 2012 for comparative purposes only.

Our Operating Revenues increased in 2013, as compared to 2012, due primarily to the addition of NSTAR's operations. During the first quarter of 2013, the former operating subsidiaries of NSTAR contributed approximately $800 million of operating revenues. Absent the first quarter 2013 NSTAR operating revenues, our Operating Revenues increased approximately $227 million due primarily to:

.

A $62.5 million increase in transmission revenues, net of applicable eliminations, as a result of the recovery of higher transmission expenses and continuing investments in our transmission infrastructure. The increase was partially offset by the establishment of a reserve related to the FERC ALJ initial decision in the third quarter of 2013.

.

A $34.3 million increase in base electric distribution revenues, net of applicable eliminations, reflecting an increase of approximately 1 percent in retail electric sales. The increase in sales volumes was driven primarily by the colder winter weather experienced throughout our service territories in early and late 2013. In addition, the increase in revenues resulted from the NHPUC-approved distribution rate increases at PSNH effective July 1, 2012 and July 1, 2013 as a result of the 2010 distribution rate case settlement. These positive impacts on revenue were partially offset by the impact of our company-sponsored energy efficiency programs.

.

A $28.8 million increase in firm natural gas distribution revenues. This increase was driven by the colder winter weather in early and late 2013, residential customer growth, an increase in natural gas conversions, the migration of interruptible customers switching to firm service rates and the addition of gas-fired distributed generation.

.

The remaining increase was due primarily to higher revenues from our tracker mechanisms related to the recovery of energy supply, retail transmission and company-sponsored energy efficiency programs. Revenues related to cost recovery mechanisms vary from period to period based on the timing of collections of the costs incurred. These revenues had no material impact on earnings.

Purchased Power, Fuel and Transmission increased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)		**2013 Increase/(Decrease) Compared to 2012**
The addition of NSTAR's operations	$	321.4
Transmission segment costs		70.8
Firm natural gas sales related costs		42.0
Partially offset by:		
Electric distribution segment fuel and energy supply costs		(13.9)
CfDs and capacity contracts		(12.0)
All other items		(9.7)
	$	398.6

Operations and Maintenance decreased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)		**Increase/(Decrease)**
The addition of NSTAR s operations	$	123.6
Partially offset by:		
Integration, merger and settlement agreement costs		(150.3)
NU s unregulated contracting business costs		(17.4)
General and administrative costs		(12.9)
Transmission segment costs		(5.2)
Natural gas segment costs		10.5
Electric distribution segment costs		1.3
All other items		(17.7)
	$	(68.1)

Depreciation increased in 2013, as compared to 2012, due primarily to the addition of NSTAR ($54.2 million) and the consolidation of CYAPC and YAEC ($13.7 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 increased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)		**Increase/(Decrease)**
The addition of NSTAR s operations	$	45.8
Recovery of transition costs at NSTAR Electric		91.9
Amortization related to CL&P s SBC and CTA		(6.8)
Other		(4.4)
	$	126.5

Amortization of Rate Reduction Bonds decreased in 2013, as compared to 2012, due primarily to the maturity of NSTAR Electric's, PSNH's, and WMECO's RRBs in 2013, partially offset by the addition of NSTAR Electric s amortization ($15.1 million).

Energy Efficiency Programs increased in 2013, as compared to 2012, due primarily to the addition of NSTAR's operations ($68.6 million), as well as an increase in energy efficiency costs in accordance with the three-year program guidelines established by the DPU at NSTAR Electric and WMECO. All costs are fully recovered through DPU-approved tracking mechanisms and therefore do not impact earnings.

Taxes Other Than Income Taxes increased in 2013, as compared to 2012, due primarily to the addition of NSTAR's operations ($37.8 million). In addition, there was an increase in property taxes ($36.6 million) as a result of an increase in Property, Plant and Equipment and an increase in the property tax rates, and an increase in the Connecticut gross earnings tax ($9.1 million) attributable to an increase in gross earnings.

Interest Expense increased $8.8 million in 2013, as compared to 2012, due primarily to the addition of NSTAR s operations ($22 million) and lower interest income on deferred transition costs ($10.6 million), partially offset by a decrease in Other Interest due primarily to the favorable impact from the resolution of a state income tax audit in the first quarter of 2013, lower interest on short-term debt ($8.8 million) and lower interest on RRBs ($6.1 million).

Other Income, Net increased $10.2 million in 2013, as compared to 2012, due primarily to higher gains on the NU supplemental benefit trust ($6 million) and an increase related to officer insurance policies ($1.7 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012[(a)]**	**Increase**	**Percent**
Income Tax Expense	$ 426.9	$ 274.9	$ 152.0	55.3%

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.

Income Tax Expense increased in 2013, as compared to 2012, due primarily to higher pre-tax earnings ($81 million), the absence in 2013 of both prior year Connecticut and Massachusetts merger settlement agreement impacts ($41 million) and integration merger impacts ($23 million), along with various other items ($7 million).

<u>Comparison of 2012 to 2011</u>:

	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 beginning April 10, 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 beginning April 10, 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 beginning April 10, 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:

(Millions of Dollars)	**2012 Increase/(Decrease) 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)
All other items		(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 beginning April 10, 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 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 beginning April 10, 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).

RESULTS OF OPERATIONS THE CONNECTICUT LIGHT AND POWER COMPANY

The following provides the amounts and variances in operating revenues and expense line items for the statements of income for CL&P included in this Annual Report on Form 10-K for the years ended December 31, 2013, 2012, and 2011:

Comparison of 2013 to 2012:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 2,442.3	$ 2,407.4	$ 34.9	1.4 %
Operating Expenses:				
Purchased Power and Transmission	872.8	858.2	14.6	1.7
Operations and Maintenance	523.2	635.7	(112.5)	(17.7)
Depreciation	177.6	166.9	10.7	6.4
Amortization of Regulatory Assets, Net	4.9	14.4	(9.5)	(66.0)
Energy Efficiency Programs	89.8	89.3	0.5	0.6
Taxes Other Than Income Taxes	234.4	215.9	18.5	8.6
Total Operating Expenses	1,902.7	1,980.4	(77.7)	(3.9)
Operating Income	$ 539.6	$ 427.0	$ 112.6	26.4 %

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

	For the Years Ended December 31,			
	2013	**2012**	**Increase**	**Percent**
Retail Sales in GWh	22,404	22,109	295	1.3 %

CL&P s Operating Revenues increased in 2013, as compared to 2012, due primarily to:

.

A $15.8 million increase in transmission revenues reflecting recovery of higher transmission expenses and continuing transmission infrastructure investments. The increase was partially offset by the establishment of a reserve related to the FERC ALJ initial decision in the third quarter of 2013.

.

A $13.5 million increase in base distribution revenues reflecting a 1.3 percent increase in retail sales. This increase was due primarily to the colder winter weather experienced in early and late 2013.

.

The remaining $5.6 million increase was due primarily to higher collections of costs through reconciling cost mechanisms. These revenues are fully reconciled to the related costs. Therefore this increase in revenues had no impact on earnings.

Purchased Power and Transmission increased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)		**2013 Increase/(Decrease) Compared to 2012**
Transmission Costs	$	45.8
Deferred Fuel Costs		28.7
GSC Supply Costs		(44.2)
Purchased Power Contracts		(12.1)
CfD Costs		(7.3)
Other		3.7
	$	14.6

The increase in transmission costs was the result of an increase in the retail transmission deferral, which related rates are adjusted on an annual basis as a result of collecting or refunding costs of the transmission systems to customers. The decrease in GSC supply costs was due primarily to lower average supply prices. On July 1, 2013, CL&P began to procure approximately thirty percent of GSC load. Costs associated with the remaining seventy percent of the GSC load 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. Purchased Power and Transmission costs are included in regulatory-approved tracking mechanisms and do not impact earnings.

Operations and Maintenance decreased in 2013, as compared to 2012, due primarily to the absence in 2013 of costs recognized in the second quarter of 2012 as a result of the Connecticut merger settlement agreement (which established a $40 million storm fund reserve and provided a $25 million bill credit to customers). In addition, there were lower distribution operating costs ($10.2 million), the absence in 2013 of amortization of the PBOP transition obligation ($6.1 million), lower distribution general and administrative costs ($7.5 million) and lower distribution costs related to customer Energy Independence Act incentives ($6.3 million). These lower costs were partially offset by an increase in distribution routine maintenance and storm-related costs ($7.4 million).

57

Depreciation increased in 2013, as compared to 2012, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net decreased in 2013, as compared to 2012, due primarily to a lower net SBC deferral, partially offset by a higher net CTA deferral. SBC revenues were $23 million lower in 2013, as compared to 2012, partially offset by higher hardship program costs of $6.6 million in 2013. CTA revenues were $13.9 million higher in 2013, as compared to 2012, and costs were $30.5 million lower in 2013, as compared to 2012. DOE refunds of $21.6 million were returned to customers in the second half of 2013.

Taxes Other Than Income Taxes increased in 2013, as compared to 2012, due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment and an increase in the property tax rates ($11.5 million). In addition, there was an increase in the Connecticut gross earnings tax attributable to an increase in gross earnings ($7.6 million).

Interest Expense increased $0.5 million in 2013, as compared to 2012, due primarily to higher interest on long-term debt ($5.7 million), partially offset by a decrease in other interest as a result of a favorable impact from the resolution of a state income tax audit in the first quarter of 2013 ($5.4 million).

Other Income increased $4.8 million in 2013, as compared to 2012, due primarily to higher gains on the NU supplemental benefit trust.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase**	**Percent**
Income Tax Expense	$ 141.7	$ 94.4	$ 47.3	50.1%

Income Tax Expense increased in 2013, as compared to 2012, due primarily to higher pre-tax earnings ($17.1 million), the absence in 2013 of the impact of costs recognized as a result of the Connecticut merger settlement agreement ($26.6 million), and higher state taxes ($5.7 million), partially offset by various other items ($2.1 million).

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. Purchased Power and Transmission costs are included in regulatory-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.

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).

EARNINGS SUMMARY

(Millions of Dollars)	For the Years Ended December 31, 2013	2012
Income Before Merger-Related Costs	$ 279.4	$ 248.1
Merger-Related Costs (after-tax) (1)	-	(38.4)
Net Income	$ 279.4	$ 209.7

(1)

The 2012 after-tax merger-related costs consisted of charges related to the Connecticut merger settlement agreement, including $14.8 million ($25 million pre-tax) for customer bill credits and $23.6 million ($40 million pre-tax) whereby CL&P agreed to forego recovery of deferred storm costs associated with Tropical Storm Irene and the October 2011 snowstorm.

Excluding the impact of merger-related costs, CL&P s earnings increased $31.3 million in 2013, as compared to 2012, due primarily to lower overall operations and maintenance costs and higher retail electric sales due primarily to colder weather in the first and fourth quarters of 2013. Partially offsetting these favorable earnings impacts was the establishment of a $7.7 million after-tax reserve related to the August 2013 FERC ALJ initial decision, higher depreciation and property tax expense.

LIQUIDITY

CL&P had cash flows provided by operating activities of $495.3 million in 2013, compared with $211.9 million in 2012. The improved cash flows were due primarily to a decrease of approximately $75 million in cash disbursements for storm restoration costs associated primarily with Tropical Storm Irene and the October 2011 snowstorm, the absence of approximately $27 million in 2012 CL&P customer bill credits associated with the October 2011 snowstorm and the absence of $25 million in 2012 CL&P customer bill credits associated with the Connecticut settlement agreement. In addition, operating cash flows benefitted from an increase in regulatory overrecoveries where such revenues exceeded costs resulting in a favorable cash flow impact, higher net income and timing of payables. Partially offsetting improved cash flows were income tax payments of $55 million in 2013, compared with income tax refunds of $42 million in 2012.

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 the $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, the $27 million in bill credits provided to residential customers in February 2012

60

related to the October 2011 snowstorm, the $25 million in bill credits to customers associated with the Connecticut merger 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.

Investments in Property, Plant and Equipment on the accompanying statements of cash flows 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 expense. CL&P s investments totaled $434.9 million in 2013, compared with $449.1 million in 2012.

On January 15, 2013, CL&P issued $400 million of 2.5 percent 2013 Series A First and Refunding Mortgage Bonds, due to mature in 2023. The proceeds, net of issuance costs, were used to pay short-term borrowings outstanding under the CL&P credit agreement of $89 million and intercompany loans related to our commercial paper program of $305.8 million. On September 3, 2013, CL&P redeemed at par $125 million of 1.25 percent Series B 2011 PCRBs, which were subject to mandatory tender for purchase, using short-term debt.

On July 31, 2013, the FERC granted authorization allowing CL&P to incur total short-term borrowings up to a maximum of $600 million, effective January 1, 2014 through December 31, 2015.

On September 6, 2013, NU parent and certain of its subsidiaries, including CL&P, amended their joint five-year $1.15 billion revolving credit facility, dated July 25, 2012, by increasing the aggregate principal amount available thereunder by $300 million to $1.45 billion, extending the expiration date from July 25, 2017 to September 6, 2018, and increasing CL&P's borrowing sub-limit from $300 million to $600 million. Simultaneously, effective September 6, 2013, the CL&P $300 million revolving credit facility was terminated. The revolving credit facility is to be used primarily to backstop the commercial paper program at NU. The commercial paper program allows NU parent to issue commercial paper as a form of short-term debt with intercompany loans to certain subsidiaries, including CL&P. As of December 31, 2013, CL&P had an intercompany loan payable to NU parent of $287.3 million related to our commercial paper program.

Other financing activities in 2013 included $152 million in common stock dividends to NU parent and a $40 million capital contribution from NU parent.

CL&P uses its available capital resources to fund its construction expenditures, meet debt requirements, pay operating costs, including storm-related costs, pay dividends and fund other corporate 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 recovers its distribution construction expenditures as the related project costs are depreciated over the life of the assets. As well, the future recovery of its deferred major storm costs will take 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 current liabilities exceeding current assets by approximately $398 million as of December 31, 2013.

As of December 31, 2013, $150 million of CL&P's obligations classified as 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, determined considering capital requirements and maintenance of CL&P s 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 SUBSIDIARY

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, 2013 and 2012:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 2,493.5	$ 2,301.0	$ 192.5	8.4 %
Operating Expenses:				
Purchased Power and Transmission	849.1	788.3	60.8	7.7
Operations and Maintenance	376.4	431.8	(55.4)	(12.8)
Depreciation	180.3	171.1	9.2	5.4
Amortization of Regulatory Assets, Net	230.1	117.7	112.4	95.5
Amortization of Rate Reduction Bonds	15.1	90.3	(75.2)	(83.3)
Energy Efficiency Programs	206.5	201.2	5.3	2.6
Taxes Other Than Income Taxes	127.8	119.2	8.6	7.2
Total Operating Expenses	1,985.3	1,919.6	65.7	3.4
Operating Income	$ 508.2	$ 381.4	$ 126.8	33.2 %

Operating Revenues

NSTAR Electric's retail sales were as follows:

	For the Years Ended December 31,			
	2013	**2012**	**Increase**	**Percent**
Retail Sales in GWh	21,306	21,209	97	0.5 %

NSTAR Electric's Operating Revenues increased in 2013, as compared to 2012, due primarily to:

.

A $160.1 million increase related to a higher level of collections of energy supply and company-sponsored energy efficiency programs. These revenues are fully reconciled to their respective costs. Therefore this increase in revenues had no material impact on earnings.

.

A $24.7 million increase in transmission revenues reflecting recovery of higher regional transmission expenses and continuing transmission infrastructure investments, offset by the establishment of a reserve related to the FERC ALJ initial decision in the third quarter of 2013.

.

A $7.7 million increase in base distribution revenues reflecting a 0.5 percent increase in retail sales. The increase in sales volume was due primarily to a greater number of cooling degree days during the summer of 2013 and heating degree days in early and late 2013. This favorable impact was partially offset by reductions due to NSTAR Electric s customer funded energy efficiency programs.

Purchased Power and Transmission increased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)	**2013 Increase/(Decrease) Compared to 2012**	
Transmission Costs	$	37.7
Basic Service Costs		20.2
Purchased Power Contracts		9.5
Deferred Fuel Costs		(6.6)
	$	60.8

The increase in transmission costs was due primarily to higher RNS costs. The increase in basic service costs was due primarily to higher average energy supply prices. The increase in purchased power contracts was due primarily to higher congestion charges. The decrease in deferred fuel costs was due primarily to higher average energy supply prices, as compared to the prices projected when basic service rates were set. Purchased Power and Transmission costs are included in regulatory-approved tracking mechanisms and do not impact earnings.

Operations and Maintenance decreased in 2013, as compared to 2012, due primarily to the absence of several adjustments recorded in the first quarter of 2012, the majority of which were recognized for changes in accounting estimates ($46.7 million), the absence of a bill credit to customers ($15 million) as a result of the Massachusetts merger settlement agreement, and an overall reduction in other operating costs ($2.1 million). These positive factors were partially offset by higher PAM-related amortizations ($4.1 million) as well as timing of maintenance ($4.3 million).

Depreciation increased in 2013, as compared to 2012, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net increased in 2013, as compared to 2012, due primarily to an increase in the recovery of previously deferred transition costs.

Amortization of Rate Reduction Bonds decreased in 2013, as compared to 2012, due to the maturity of the RRBs in March 2013.

Energy Efficiency Programs increased in 2013, as compared to 2012, due primarily to 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-approved tracking mechanisms and therefore do not impact earnings.

Taxes Other Than Income Taxes increased in 2013, as compared to 2012, due to higher municipal property taxes as a result of an increase in Property, Plant and Equipment.

Interest Expense increased $0.3 million in 2013, as compared to 2012, due primarily to lower regulatory interest income primarily from deferred transition costs, partially offset by lower average long-term bond rates.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase**	**Percent**
Income Tax Expense	$ 172.9	$ 124.0	$ 48.9	39.4%

Income Tax Expense increased in 2013, as compared to 2012, due primarily to higher pre-tax earnings ($44 million) and the absence in 2013 of the impact of costs recognized as a result of the Massachusetts merger settlement agreement ($5.9 million), partially offset by various other impacts ($1 million).

EARNINGS SUMMARY

	For the Years Ended December 31,	
(Millions of Dollars)	**2013**	**2012**
Income Before Merger-Related Costs	$ 268.5	$ 201.1
Merger-Related Costs (after-tax) [(1)]	-	(10.9)

Net Income	$	268.5	$	190.2

(1)

The 2012 after-tax merger-related costs consisted of a $15 million pre-tax charge for customer bill credits related to the Massachusetts merger settlement agreement and a $2.8 million pre-tax charge related to compensation costs.

Excluding the impact of merger-related costs, NSTAR Electric s earnings increased $67.4 million in 2013, as compared to 2012, due primarily to lower overall operations and maintenance costs and higher retail electric sales due primarily to colder weather in the first and fourth quarters in 2013. Partially offsetting these factors was higher depreciation and property tax expense.

CAPITAL EXPENDITURES

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

	For the Years Ended December 31,					
(Millions of Dollars)	**2013**		**2012**		**2011**	
Transmission	$	220.8	$	192.1	$	162.5
Distribution:						
Basic Business		98.5		64.2		58.5
Aging Infrastructure		110.6		145.8		132.8
Load Growth		53.6		21.2		19.3
Total Distribution		262.7		231.2		210.6
Total	$	483.5	$	423.3	$	373.1

LIQUIDITY

NSTAR Electric had cash flows provided by operating activities of $466.9 million in 2013, compared with $506.9 million in 2012 (amounts are net of RRB payments, which are included in financing activities). The decrease in operating cash flows was due primarily to a $57 million increase in Pension Plan contributions in 2013, as compared to 2012, and a $75.3 million increase in net tax payments. Partially offsetting the negative cash flow impacts was the absence in 2013 of $15 million in bill credits provided to customers in the second quarter of 2012 in connection with the Massachusetts merger settlement agreement. In addition, operating cash flows benefitted from an increase in amortization on regulatory deferrals primarily attributable to tracking mechanisms where such revenues exceeded costs resulting in a favorable cash flow impact.

RESULTS OF OPERATIONS   PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY

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, 2013 and 2012:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 935.4	$ 988.0	$ (52.6)	(5.3)%
Operating Expenses:				
Purchased Power, Fuel and Transmission	269.8	319.3	(49.5)	(15.5)
Operations and Maintenance	267.8	263.2	4.6	1.7
Depreciation	91.6	87.6	4.0	4.6
Amortization of Regulatory Liabilities, Net	(20.4)	(24.1)	3.7	15.4
Amortization of Rate Reduction Bonds	19.7	56.6	(36.9)	(65.2)
Energy Efficiency Programs	14.5	14.2	0.3	2.1
Taxes Other Than Income Taxes	67.2	66.1	1.1	1.7
Total Operating Expenses	710.2	782.9	(72.7)	(9.3)
Operating Income	$ 225.2	$ 205.1	$ 20.1	9.8 %

Operating Revenues

PSNH's retail sales were as follows:

	For the Years Ended December 31,			
	2013	**2012**	**Increase**	**Percent**
Retail Sales in GWh	7,938	7,821	117	1.5 %

PSNH's Operating Revenues decreased in 2013, as compared to 2012, due primarily to:

.

A $73.2 million decrease related to PSNH's cost recovery mechanisms. The primary reason for this decrease was the reduction of recoveries related to PSNH s RRBs, which were fully collected during the first half of 2013.This reduction had no impact on earnings.

Partially offset by:

.

A $17.3 million increase in base distribution revenues reflecting a 1.5 percent increase in retail sales. PSNH experienced strong sales in early and late 2013 due to colder winter weather than what was experienced in 2012. Also reflected in this revenue increase was an increase of $11.9 million related to NHPUC-approved distribution rate increases effective July 1, 2012 and July 1, 2013 as a result of the 2010 distribution rate case settlement.

.

A $3.3 million increase in transmission revenues reflecting recovery of higher transmission expenses and continuing transmission infrastructure investments. The increase was mostly offset by the establishment of a reserve related to the FERC ALJ initial decision in the third quarter of 2013.

Purchased Power, Fuel and Transmission decreased in 2013, as compared to 2012, due primarily to a decrease in costs related to renewable energy and a decrease in fuel costs resulting from an increase in customer migration to third party suppliers, which resulted in a decrease in load obligation. These decreases were partially offset by an increase in transmission costs resulting from higher RNS costs. Purchased Power, Fuel and Transmission costs are included in regulatory-approved tracking mechanisms and do not impact earnings.

Operations and Maintenance increased in 2013, as compared to 2012, due primarily to an increase in routine maintenance and storm-related distribution overhead line costs ($11.4 million) and an increase in routine generation maintenance costs ($4.4 million). Partially offsetting these increases was the absence in 2013 of PBOP transition obligation amortization ($2.5 million), lower distribution general and administrative costs ($3 million), a decrease in RRB charges that are included in NHPUC-approved tracking mechanisms ($2.9 million), and a decrease in routine transmission maintenance ($1.4 million).

Depreciation increased in 2013, as compared to 2012, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Liabilities, Net increased expenses in 2013, as compared to 2012, due primarily to an increase in the ES and TCAM amortization ($23.3 million and $9.2 million, respectively), partially offset by a decrease in the SCRC amortization ($27.9 million).

Amortization of Rate Reduction Bonds decreased in 2013, as compared to 2012, due to the maturity of the RRBs in May 2013.

Taxes Other Than Income Taxes increased in 2013, as compared to 2012, due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment and an increase in the property tax rates.

64

Interest Expense decreased $4.1 million in 2013, as compared to 2012, due primarily to lower interest on RRBs ($2.8 million) as a result of the maturity of the RRBs in May 2013, and a decrease in interest on long-term debt ($1.9 million) due primarily to the redemption of the 2001 Series C PCRBs in May 2013.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase**	**Percent**
Income Tax Expense	$ 71.1	$ 61.0	$ 10.1	16.6%

Income Tax Expense increased in 2013, as compared to 2012, due primarily to higher pre-tax earnings ($8.6 million) and various other impacts ($1.5 million).

EARNINGS SUMMARY

	For the Years Ended December 31,		
(Millions of Dollars)	**2013**	**2012**	**Increase**
Net Income	$ 111.4	$ 96.9	$ 14.5

PSNH s earnings increased due primarily to higher generation earnings and distribution retail revenues. The 2013 distribution retail revenues were favorably impacted by the PSNH rate increases effective July 1, 2012 and July 1, 2013 as a result of the 2010 distribution rate case settlement and a 1.5 percent increase in retail sales. PSNH experienced strong sales in early and late 2013 due to colder winter weather than what was experienced in 2012. Partially offsetting these favorable earnings impacts were higher depreciation and property tax expense.

LIQUIDITY

PSNH had cash flows provided by operating activities of $158.8 million in 2013, compared with $174.2 million in 2012 (amounts are net of RRB payments, which are included in financing activities). The decrease in cash flows was due primarily to an increase in NUSCO Pension Plan contributions of $20.6 million in 2013, as compared to 2012, and an increase in coal and fuel inventories in 2013 creating a negative cash flow impact of $34.6 million, as compared to a reduction in coal and fuel inventories in 2012 creating a positive cash flow impact of $28.1 million. Partially offsetting these decreases were income tax refunds of $30.1 million in 2013, compared to income tax payments of $14.7 million in 2012, the absence of $13.7 million of 2012 cash disbursements for storm costs associated with Tropical Storm Irene and the October 2011 snowstorm and the favorable impacts related to the distribution rate increases effective July 1, 2012 and July 1, 2013 as a result of the 2010 distribution rate case settlement.

RESULTS OF OPERATIONS WESTERN MASSACHUSETTS ELECTRIC COMPANY

The following table provides the amounts and variances in operating revenues and expense line items for the statements of income for WMECO included in this Annual Report on Form 10-K for the years ended December 31, 2013 and 2012:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 472.7	$ 441.2	$ 31.5	7.1 %
Operating Expenses:				
Purchased Power and Transmission	147.1	136.1	11.0	8.1
Operations and Maintenance	96.2	97.0	(0.8)	(0.8)
Depreciation	37.6	30.0	7.6	25.3
Amortization of Regulatory (Liabilities)/Assets, Net	(3.2)	0.4	(3.6)	(a)
Amortization of Rate Reduction Bonds	7.8	17.6	(9.8)	(55.7)
Energy Efficiency Programs	39.5	27.8	11.7	42.1
Taxes Other Than Income Taxes	28.4	21.5	6.9	32.1
Total Operating Expenses	353.4	330.4	23.0	7.0
Operating Income	$ 119.3	$ 110.8	$ 8.5	7.7 %

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

Operating Revenues

WMECO's retail sales were as follows:

	For the Years Ended December 31,			
	2013	**2012**	**Change**	**Percent**
Retail Sales in GWh	3,683	3,683	-	- %

WMECO's Operating Revenues increased in 2013, as compared to 2012, due primarily to:

.

A $21.3 million increase in transmission revenues reflecting recovery of higher transmission expenses and continuing transmission infrastructure investments, primarily related to the NEEWS project. The increase was partially offset by the establishment of a reserve related to the FERC ALJ initial decision in the third quarter of 2013.

.

Base distribution revenues are consistent with 2012, as they are decoupled from sales volumes.

.

The remaining increase primarily reflects a higher level of collections related to WMECO s energy supply and company-sponsored energy efficiency programs. These revenues are fully reconciled to the related costs. Therefore this increase in revenues had no material impact on earnings.

Purchased Power and Transmission increased in 2013, as compared to 2012, due primarily to an increase in supplier contract prices. Purchased Power and Transmission costs are included in regulatory-approved tracking mechanisms and do not impact earnings.

Operations and Maintenance decreased in 2013, as compared to 2012, due primarily to the absence in 2013 of bill credits to customers ($3 million) made in the second quarter of 2012 as a result of the Massachusetts merger settlement agreement and the absence in 2013 of the DPU storm penalty ($2 million). In addition, there were lower general and administrative expenses ($2.5 million). Partially offsetting these decreases was an increase in Pension and PBOP Plan costs ($6.6 million), which is recovered through DPU-approved tracking mechanisms and has no earnings impact.

Depreciation increased in 2013, as compared to 2012, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory (Liabilities)/Assets, Net decreased in 2013, as compared to 2012, due primarily to a decrease in amortization of the transition charge deferral.

Amortization of Rate Reduction Bonds decreased in 2013, as compared to 2012, due to the maturity of the RRBs in June 2013.

Energy Efficiency Programs increased in 2013, as compared to 2012, due primarily to an increase in expenses attributable to an increase in spending in accordance with the three-year program guidelines established by the DPU. All costs are fully recovered through DPU-approved tracking mechanisms and therefore do not impact earnings.

Taxes Other Than Income Taxes increased in 2013, as compared to 2012, due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment and an increase in the property tax rates.

Interest Expense decreased $1.8 million in 2013, as compared to 2012, due primarily to lower interest on RRBs ($1.1 million) as a result of the maturity of the RRBs in June 2013, and lower interest on short-term debt ($0.9 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2013**	**2012**	**Increase**	**Percent**
Income Tax Expense	$ 37.4	$ 32.1	$ 5.3	16.5%

Income Tax Expense increased in 2013, as compared to 2012, due primarily to higher pre-tax earnings ($2.9 million), the absence in 2013 of the impact of costs recognized as a result of the Massachusetts merger settlement agreement ($1.2 million) and various other impacts ($1.2 million).

EARNINGS SUMMARY

	For the Years Ended December 31,	
(Millions of Dollars)	**2013**	**2012**
Income Before Merger-Related Costs	$ 60.4	$ 56.3
Merger-Related Costs (after-tax)	-	(1.8)
Net Income	$ 60.4	$ 54.5

Excluding the impact of merger-related costs, WMECO s earnings increased $4.1 million, as compared to 2012, due primarily to higher transmission earnings as a result of an increased level of investment in transmission infrastructure, primarily related to the NEEWS project. Partially offsetting this favorable earnings impact was higher depreciation and property tax expense.

LIQUIDITY

WMECO had cash flows provided by operating activities of $169.5 million in 2013, compared with $77 million in 2012 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows were due primarily to income tax refunds of $69 million in 2013, compared with income tax refunds of $8.4 million in 2012, the absence of $16.7 million in 2012 cash disbursements for storm costs in 2012 and the absence of $3 million in bill credits provided to customers in the second quarter of 2012 associated with the Massachusetts merger settlement agreement.

67

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. NU s Energy Supply Risk Committee, comprised of senior officers, reviews and approves all large scale energy related transactions entered into by its Regulated Companies.

The remaining unregulated wholesale marketing contracts expired on December 31, 2013 and therefore, there is no remaining market risk exposure related to these contracts.

Other Risk Management Activities

We have an Enterprise Risk Management methodology for identifying the principal risks of the Company. Our ERM program involves the application of a well-defined, enterprise-wide methodology designed to allow our Risk Committee, comprised of our senior officers and directors to the company, 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 and mitigation strategies. Management broadly considers our business model, the utility industry, the global economy and the current environment to identify risks. The findings of this process are periodically discussed with the Finance Committee of our Board of Trustees. 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.

Interest Rate Risk Management: As of December 31, 2013, 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 $7.7 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 transact with 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, 2013, our Regulated companies held collateral from counterparties related to our standard service contracts. As of December 31, 2013, NU had cash posted with ISO-NE related to energy purchase transactions.

For further information on cash collateral deposited and posted with counterparties as well, 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* (1992 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, 2013.

February 25, 2014

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, 2013 and 2012, 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, 2013. 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, 2013, based on criteria established in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Company Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in *Internal Control Integrated Framework(1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 25, 2014

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,			
(Thousands of Dollars)		2013		2012
ASSETS				
Current Assets:				
Cash and Cash Equivalents	$	43,364	$	45,748
Receivables, Net		765,391		792,822
Unbilled Revenues		224,982		216,040
Fuel, Materials and Supplies		303,233		267,713
Regulatory Assets		535,791		705,025
Prepayments and Other Current Assets		214,288		199,947
Total Current Assets		2,087,049		2,227,295
Property, Plant and Equipment, Net		17,576,186		16,605,010
Deferred Debits and Other Assets:				
Regulatory Assets		3,758,694		5,132,411
Goodwill		3,519,401		3,519,401
Marketable Securities		488,515		400,329
Derivative Assets		74,155		90,612
Other Long-Term Assets		291,537		327,766
Total Deferred Debits and Other Assets		8,132,302		9,470,519
Total Assets	$	27,795,537	$	28,302,824

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

		As of December 31,		
(Thousands of Dollars)		2013		2012
LIABILITIES AND CAPITALIZATION				
Current Liabilities:				
Notes Payable	$	1,093,000	$	1,120,196
Long-Term Debt - Current Portion		533,346		763,338
Accounts Payable		742,251		764,350
Regulatory Liabilities		204,278		134,115
Other Current Liabilities		702,776		861,691
Total Current Liabilities		3,275,651		3,643,690
Rate Reduction Bonds		-		82,139
Deferred Credits and Other Liabilities:				
Accumulated Deferred Income Taxes		4,029,026		3,463,347
Regulatory Liabilities		502,984		540,162
Derivative Liabilities		624,050		882,654
Accrued Pension, SERP and PBOP		896,844		2,130,497
Other Long-Term Liabilities		923,053		967,561
Total Deferred Credits and Other Liabilities		6,975,957		7,984,221
Capitalization:				
Long-Term Debt		7,776,833		7,200,156
Noncontrolling Interest - Preferred Stock of Subsidiaries		155,568		155,568
Equity:				
Common Shareholders' Equity:				
Common Shares		1,665,351		1,662,547
Capital Surplus, Paid In		6,192,765		6,183,267
Retained Earnings		2,125,980		1,802,714
Accumulated Other Comprehensive Loss		(46,031)		(72,854)
Treasury Stock		(326,537)		(338,624)
Common Shareholders' Equity		9,611,528		9,237,050
Total Capitalization		17,543,929		16,592,774
Commitments and Contingencies (Note 12)				
Total Liabilities and Capitalization	$	27,795,537	$	28,302,824

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

73

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars, Except Share Information)	2013	2012	2011
Operating Revenues	$ 7,301,204	$ 6,273,787	$ 4,465,657
Operating Expenses:			
Purchased Power, Fuel and Transmission	2,482,954	2,084,364	1,657,914
Operations and Maintenance	1,514,986	1,583,070	1,095,358
Depreciation	610,777	519,010	302,192
Amortization of Regulatory Assets, Net	206,322	79,762	91,080
Amortization of Rate Reduction Bonds	42,581	142,019	69,912
Energy Efficiency Programs	401,919	313,149	131,415
Taxes Other Than Income Taxes	512,230	434,207	323,610
Total Operating Expenses	5,771,769	5,155,581	3,671,481
Operating Income	1,529,435	1,118,206	794,176
Interest Expense:			
Interest on Long-Term Debt	340,970	316,987	231,630
Interest on Rate Reduction Bonds	422	6,168	8,611
Other Interest	(2,693)	6,790	10,184
Interest Expense	338,699	329,945	250,425
Other Income, Net	29,894	19,742	27,715
Income Before Income Tax Expense	1,220,630	808,003	571,466
Income Tax Expense	426,941	274,926	170,953
Net Income	793,689	533,077	400,513
Net Income Attributable to Noncontrolling Interests	7,682	7,132	5,820
Net Income Attributable to Controlling Interest	$ 786,007	$ 525,945	$ 394,693
Basic Earnings Per Common Share	$ 2.49	$ 1.90	$ 2.22
Diluted Earnings Per Common Share	$ 2.49	$ 1.89	$ 2.22
Weighted Average Common Shares Outstanding:			
Basic	315,311,387	277,209,819	177,410,167
Diluted	316,211,160	277,993,631	177,804,568

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2013	2012	2011
Net Income	$ 793,689	$ 533,077	$ 400,513
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	2,049	1,971	(14,177)
Changes in Unrealized Gains/(Losses) on Other Securities	(940)	217	506
Change in Funded Status of Pension, SERP and PBOP Benefit Plans	25,714	(4,356)	(13,645)
Other Comprehensive Income/(Loss), Net of Tax	26,823	(2,168)	(27,316)
Comprehensive Income Attributable to Noncontrolling Interests	(7,682)	(7,132)	(5,820)
Comprehensive Income Attributable to Controlling Interest	$ 812,830	$ 523,777	$ 367,377

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(Thousands of Dollars, Except Share Information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Common Shareholders' Equity
Balance as of January 1, 2011	176,448,081	$ 978,909	$ 1,777,592	$ 1,452,777	$ (43,370)	$ (354,732)	$ 3,811,176
Net Income				400,513			400,513
Dividends on Common Shares - $1.10 Per Share				(195,595)			(195,595)
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
Long-Term Incentive Plan Activity			(3,897)				(3,897)
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
Net Income				793,689			793,689
Dividends on Common Shares - $1.47 Per Share				(462,741)			(462,741)
Dividends on Preferred Stock				(7,682)			(7,682)
Issuance of Common Shares, $5 Par Value	560,848	2,804	8,274				11,078
Long-Term Incentive Plan Activity			(10,748)				(10,748)
Issuance of Treasury Shares	659,077		17,381			12,087	29,468
Other Changes in Shareholders' Equity			(5,409)				(5,409)
Other Comprehensive Income					26,823		26,823
Balance as of December 31, 2013	315,273,559	$ 1,665,351	$ 6,192,765	$ 2,125,980	$ (46,031)	$ (326,537)	$ 9,611,528

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)	2013	2012	2011
Operating Activities:			
Net Income	$ 793,689	$ 533,077	$ 400,513
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	610,777	519,010	302,192
Deferred Income Taxes	431,413	292,000	196,761
Pension, SERP and PBOP Expense	195,698	218,540	133,000
Pension and PBOP Contributions	(342,184)	(295,028)	(191,101)
Regulatory Underrecoveries, Net	(24,276)	(259,853)	(70,863)
Amortization of Regulatory Assets, Net	206,322	79,762	91,080
Amortization of Rate Reduction Bonds	42,581	142,019	69,912
Other	56,071	42,852	(48,772)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(163,549)	(20,214)	17,570
Fuel, Materials and Supplies	(14,811)	34,321	(11,033)
Taxes Receivable/Accrued, Net	(50,950)	(5,450)	49,642
Accounts Payable	(54,619)	(128,339)	18,916
Other Current Assets and Liabilities, Net	(22,623)	8,532	12,569
Net Cash Flows Provided by Operating Activities	1,663,539	1,161,229	970,386
Investing Activities:			
Investments in Property, Plant and Equipment	(1,456,787)	(1,472,272)	(1,076,730)
Proceeds from Sales of Marketable Securities	627,532	317,294	149,441
Purchases of Marketable Securities	(679,784)	(348,629)	(151,972)
Other Investing Activities	67,816	35,683	60,674
Net Cash Flows Used in Investing Activities	(1,441,223)	(1,467,924)	(1,018,587)
Financing Activities:			
Cash Dividends on Common Shares	(462,741)	(375,047)	(194,555)
Cash Dividends on Preferred Stock	(7,682)	(7,029)	(5,559)
(Decrease)/Increase in Short-Term Debt	(397,000)	825,000	50,000
Issuance of Long-Term Debt	1,680,000	850,000	627,500
Retirements of Long-Term Debt	(929,885)	(839,136)	(369,586)
Retirements of Rate Reduction Bonds	(82,139)	(114,433)	(69,312)
Other Financing Activities	(25,253)	6,529	(7,123)
	(224,700)	345,884	31,365

Net Cash Flows (Used in)/Provided by Financing Activities						
Net (Decrease)/Increase in Cash and Cash Equivalents		(2,384)		39,189		(16,836)
Cash and Cash Equivalents - Beginning of Year		45,748		6,559		23,395
Cash and Cash Equivalents - End of Year	$	43,364	$	45,748	$	6,559

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

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company s internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of 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* (1992 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, 2013.

February 25, 2014

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 balance sheets of The Connecticut Light and Power Company (the "Company") as of December 31, 2013 and 2012, and the related statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 2013. 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 financial statements present fairly, in all material respects, the financial position of The Connecticut Light and Power Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, 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 financial statements taken as a whole presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 25, 2014

THE CONNECTICUT LIGHT AND POWER COMPANY
BALANCE SHEETS

		As of December 31,		
(Thousands of Dollars)		2013		2012
ASSETS				
Current Assets:				
Cash	$	7,237	$	1
Receivables, Net		319,670		284,787
Accounts Receivable from Affiliated Companies		13,777		6,641
Unbilled Revenues		92,401		85,353
Regulatory Assets		150,943		185,858
Materials and Supplies		54,606		64,603
Prepayments and Other Current Assets		53,082		26,413
Total Current Assets		691,716		653,656
Property, Plant and Equipment, Net		6,451,259		6,152,959
Deferred Debits and Other Assets:				
Regulatory Assets		1,663,147		2,158,363
Derivative Assets		71,384		90,612
Other Long-Term Assets		102,996		86,498
Total Deferred Debits and Other Assets		1,837,527		2,335,473
Total Assets	$	8,980,502	$	9,142,088

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

THE CONNECTICUT LIGHT AND POWER COMPANY
BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2013	2012
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ 287,300	$ 99,296
Long-Term Debt - Current Portion	150,000	125,000
Accounts Payable	201,047	262,857
Accounts Payable to Affiliated Companies	56,531	52,326
Obligations to Third Party Suppliers	73,914	67,344
Accrued Taxes	37,186	60,109
Regulatory Liabilities	93,961	32,119
Derivative Liabilities	92,233	96,931
Other Current Liabilities	97,530	125,662
Total Current Liabilities	1,089,702	921,644
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,510,586	1,336,105
Regulatory Liabilities	93,757	124,319
Derivative Liabilities	617,072	865,571
Accrued Pension, SERP and PBOP	95,895	304,696
Other Long-Term Liabilities	163,588	197,434
Total Deferred Credits and Other Liabilities	2,480,898	2,828,125
Capitalization:		
Long-Term Debt	2,591,208	2,737,790
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	1,682,047	1,640,149
Retained Earnings	961,482	839,628
Accumulated Other Comprehensive Loss	(1,387)	(1,800)
Common Stockholder's Equity	2,702,494	2,538,329
Total Capitalization	5,409,902	5,392,319
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 8,980,502	$ 9,142,088

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

81

THE CONNECTICUT LIGHT AND POWER COMPANY
STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2013	2012	2011
Operating Revenues	$ 2,442,341	$ 2,407,449	$ 2,548,387
Operating Expenses:			
Purchased Power and Transmission	872,769	858,231	982,514
Operations and Maintenance	523,247	635,733	580,736
Depreciation	177,603	166,853	157,747
Amortization of Regulatory Assets, Net	4,870	14,372	61,025
Energy Efficiency Programs	89,858	89,299	90,297
Taxes Other Than Income Taxes	234,418	215,972	212,885
Total Operating Expenses	1,902,765	1,980,460	2,085,204
Operating Income	539,576	426,989	463,183
Interest Expense:			
Interest on Long-Term Debt	130,620	124,894	131,918
Other Interest	3,030	8,233	809
Interest Expense	133,650	133,127	132,727
Other Income, Net	15,149	10,300	9,741
Income Before Income Tax Expense	421,075	304,162	340,197
Income Tax Expense	141,663	94,437	90,033
Net Income	$ 279,412	$ 209,725	$ 250,164

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

STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 279,412	$ 209,725	$ 250,164
Other Comprehensive Income, Net of Tax:			
Qualified Cash Flow Hedging Instruments	444	444	445
Changes in Unrealized Gains/(Losses) on Other Securities	(31)	7	17
Other Comprehensive Income, Net of Tax	413	451	462
Comprehensive Income	$ 279,825	$ 210,176	$ 250,626

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

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

(Thousands of Dollars, Except Stock Information)	Common Stock Stock	Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
Balance as of January 1, 2011	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
Net Income				279,412		279,412
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(151,999)		(151,999)
Allocation of Benefits - ESOP			1,847			1,847
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			40,000			40,000
Other Comprehensive Income					413	413
Balance as of December 31, 2013	6,035,205	$ 60,352	$ 1,682,047	$ 961,482	$ (1,387)	$ 2,702,494

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

THE CONNECTICUT LIGHT AND POWER COMPANY
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2013	2012	2011
Operating Activities:			
Net Income	$ 279,412	$ 209,725	$ 250,164
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	177,603	166,853	157,747
Deferred Income Taxes	130,038	140,993	112,620
Pension, SERP and PBOP Expense, Net of PBOP Contributions	24,416	24,062	10,664
Regulatory Over/(Under) Recoveries, Net	28,298	(100,505)	(82,502)
Amortization of Regulatory Assets, Net	4,870	14,372	61,025
Other	(3,478)	(28,952)	(33,713)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(56,593)	(7,741)	14,610
Materials and Supplies	9,997	(4,573)	(2,206)
Taxes Receivable/Accrued, Net	(41,594)	15,702	2,719
Accounts Payable	(66,225)	(190,240)	8,864
Other Current Assets and Liabilities, Net	8,513	(27,803)	13,291
Net Cash Flows Provided by Operating Activities	495,257	211,893	513,283
Investing Activities:			
Investments in Property, Plant and Equipment	(434,934)	(449,137)	(424,865)
Proceeds from Sale of Assets	-	-	46,841
Other Investing Activities	2,650	32,009	16,001
Net Cash Flows Used in Investing Activities	(432,284)	(417,128)	(362,023)
Financing Activities:			
Cash Dividends on Common Stock	(151,999)	(100,486)	(243,218)
Cash Dividends on Preferred Stock	(5,559)	(5,559)	(5,559)
(Decrease)/Increase in Short-Term Debt	(89,000)	58,000	31,000
(Decrease)/Increase in Notes Payable to Affiliate	(117,800)	346,575	52,300
Issuance of Long-Term Debt	400,000	-	245,500
Retirements of Long-Term Debt	(125,000)	(116,400)	(245,500)
Capital Contributions from NU Parent	40,000	25,000	6,748
Other Financing Activities	(6,379)	(1,895)	(2,292)
Net Cash Flows (Used in)/Provided by Financing Activities	(55,737)	205,235	(161,021)

Net Increase/(Decrease) in Cash	7,236	-	(9,761)
Cash - Beginning of Year	1	1	9,762
Cash - End of Year	$ 7,237	$ 1	$ 1

The accompanying notes are an integral part of these 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 subsidiary (NSTAR Electric or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company s internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of 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* (1992 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, 2013.

February 25, 2014

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 sheets of NSTAR Electric Company and subsidiary (the "Company") as of December 31, 2013 and 2012 and the related consolidated statements of income, common stockholder s equity, and cash flows for each of the two years in the period ended December 31, 2013. 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. The consolidated financial statements and financial statement schedule of the Company for the year ended December 31, 2011 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 audits 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. 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 NSTAR Electric Company and subsidiary as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 2013 and 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 25, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Directors and Shareholder of NSTAR Electric Company:

In our opinion, the consolidated statements of income, common stockholder's equity, and cash flows present fairly, in all material respects, the results of operations and cash flows of NSTAR Electric Company and its subsidiaries for the year 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 the year 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Boston, Massachusetts

February 7, 2012

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2013		2012	
ASSETS				
Current Assets:				
Cash and Cash Equivalents	$	8,021	$	13,695
Receivables, Net		209,711		202,025
Accounts Receivable from Affiliated Companies		27,264		160,176
Unbilled Revenues		41,368		41,377
Materials and Supplies		44,236		26,754
Regulatory Assets		204,144		347,081
Prepayments and Other Current Assets		36,710		1,332
Total Current Assets		571,454		792,440
Property, Plant and Equipment, Net		5,043,887		4,735,297
Deferred Debits and Other Assets:				
Regulatory Assets		1,235,156		1,444,870
Other Long-Term Assets		60,624		87,382
Total Deferred Debits and Other Assets		1,295,780		1,532,252
Total Assets	$	6,911,121	$	7,059,989

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

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2013	2012
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable	$ 103,500	$ 276,000
Long-Term Debt - Current Portion	301,650	1,650
Accounts Payable	207,559	168,611
Accounts Payable to Affiliated Companies	75,707	247,061
Accumulated Deferred Income Taxes	50,128	104,668
Regulatory Liabilities	53,958	47,539
Other Current Liabilities	118,410	144,433
Total Current Liabilities	910,912	989,962
Rate Reduction Bonds	-	43,493
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,466,835	1,321,026
Regulatory Liabilities	253,108	244,224
Accrued Pension	118,010	360,932
Payable to Affiliated Companies	64,172	70,221
Other Long-Term Liabilities	142,214	183,190
Total Deferred Credits and Other Liabilities	2,044,339	2,179,593
Capitalization:		
Long-Term Debt	1,499,417	1,600,911
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	1,420,828	1,210,405
Common Stockholder's Equity	2,413,453	2,203,030
Total Capitalization	3,955,870	3,846,941
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 6,911,121	$ 7,059,989

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

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2013	2012	2011
Operating Revenues	$ 2,493,479	$ 2,300,997	$ 2,403,053
Operating Expenses:			
Purchased Power and Transmission	849,149	788,252	905,226
Operations and Maintenance	376,360	431,802	387,533
Depreciation	180,298	171,070	163,368
Amortization of Regulatory Assets, Net	230,148	117,682	82,979
Amortization of Rate Reduction Bonds	15,054	90,322	90,322
Energy Efficiency Programs	206,536	201,234	175,747
Taxes Other Than Income Taxes	127,778	119,219	111,705
Total Operating Expenses	1,985,323	1,919,581	1,916,880
Operating Income	508,156	381,416	486,173
Interest Expense:			
Interest on Long-Term Debt	79,088	87,100	90,040
Interest on Rate Reduction Bonds	399	3,585	7,226
Other Interest	(9,104)	(20,631)	(27,839)
Interest Expense	70,383	70,054	69,427
Other Income, Net	3,639	2,846	1,434
Income Before Income Tax Expense	441,412	314,208	418,180
Income Tax Expense	172,866	123,966	165,686
Net Income	$ 268,546	$ 190,242	$ 252,494

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

NSTAR 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	Total Common Stockholder's Equity
Balance as of January 1, 2011	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
Net Income				268,546	268,546
Dividends on Preferred Stock				(2,123)	(2,123)
Dividends on Common Stock				(56,000)	(56,000)
Balance as of December 31, 2013	100	$ -	$ 992,625	$ 1,420,828	$ 2,413,453

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

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2013	2012	2011
Operating Activities:			
Net Income	$ 268,546	$ 190,242	$ 252,494
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	180,298	171,070	163,368
Deferred Income Taxes	48,808	4,264	72,006
Pension Expense	35,731	66,010	54,704
Pension Contributions	(82,000)	(25,000)	(125,000)
Regulatory (Under)/Over Recoveries, Net	(119,433)	(16,129)	68,353
Amortization of Regulatory Assets, Net	230,148	117,682	82,979
Amortization of Rate Reduction Bonds	15,054	90,322	90,322
Bad Debt Expense	28,108	40,301	22,582
Other	4,428	(32,048)	539
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(45,405)	(10,496)	(26,041)
Materials and Supplies	3,227	1,813	(12,968)
Taxes Receivable/Accrued, Net	(38,003)	29,899	149,889
Accounts Payable	31,875	2,662	(53,939)
Accounts Receivable from/Payable to Affiliates, Net	(44,491)	(61,879)	(7,232)
Other Current Assets and Liabilities, Net	(6,468)	22,568	14,272
Net Cash Flows Provided by Operating Activities	510,423	591,281	746,328
Investing Activities:			
Investments in Property, Plant and Equipment	(476,600)	(414,089)	(390,427)
Decrease/(Increase) in Special Deposits	37,604	3,060	(2,732)
Other Investing Activities	400	400	6,095
Net Cash Flows Used in Investing Activities	(438,596)	(410,629)	(387,064)
Financing Activities:			
Cash Dividends on Common Stock	(56,000)	(217,000)	(169,900)
Cash Dividends on Preferred Stock	(2,123)	(1,960)	(1,960)
(Decrease)/Increase in Short-Term Debt	(172,500)	134,500	(86,000)
Issuance of Long-Term Debt	200,000	400,000	-
Retirements of Long-Term Debt	(1,650)	(401,650)	(16,650)

Retirements of Rate Reduction Bonds	(43,493)	(84,367)	(84,346)
Other Financing Activities	(1,735)	(5,853)	-
Net Cash Flows Used in Financing Activities	(77,501)	(176,330)	(358,856)
Net (Decrease)/Increase in Cash and Cash Equivalents	(5,674)	4,322	408
Cash and Cash Equivalents - Beginning of Year	13,695	9,373	8,965
Cash and Cash Equivalents - End of Year	$ 8,021	$ 13,695	$ 9,373

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

This Page Intentionally Left Blank

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 subsidiary (PSNH or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company s internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of 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* (1992 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, 2013.

February 25, 2014

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 subsidiary (the "Company") as of December 31, 2013 and 2012 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, 2013. 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 subsidiary as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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 presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 25, 2014

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2013	2012
ASSETS		
Current Assets:		
Cash	$ 130	$ 2,493
Receivables, Net	76,331	87,164
Accounts Receivable from Affiliated Companies	90	723
Unbilled Revenues	38,344	39,982
Taxes Receivable	2,180	17,177
Fuel, Materials and Supplies	128,736	95,345
Regulatory Assets	92,194	62,882
Prepayments and Other Current Assets	21,920	22,205
Total Current Assets	359,925	327,971
Property, Plant and Equipment, Net	2,467,556	2,352,515
Deferred Debits and Other Assets:		
Regulatory Assets	219,346	351,059
Other Long-Term Assets	39,891	83,052
Total Deferred Debits and Other Assets	259,237	434,111
Total Assets	$ 3,086,718	$ 3,114,597

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2013	2012
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ 86,500	$ 63,300
Long-Term Debt - Current Portion	50,000	-
Accounts Payable	82,920	62,864
Accounts Payable to Affiliated Companies	22,040	21,337
Regulatory Liabilities	20,643	23,002
Accumulated Deferred Income Taxes	28,596	10,364
Renewable Portfolio Standards Compliance Obligations	8,918	17,383
Other Current Liabilities	42,811	40,586
Total Current Liabilities	342,428	238,836
Rate Reduction Bonds	-	29,294
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	500,166	441,577
Regulatory Liabilities	51,723	52,418
Accrued Pension	-	186,148
Accrued SERP and PBOP	15,272	33,981
Other Long-Term Liabilities	46,247	47,896
Total Deferred Credits and Other Liabilities	613,408	762,020
Capitalization:		
Long-Term Debt	999,006	997,932
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	701,911	701,052
Retained Earnings	438,515	395,118
Accumulated Other Comprehensive Loss	(8,550)	(9,655)
Common Stockholder's Equity	1,131,876	1,086,515
Total Capitalization	2,130,882	2,084,447
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 3,086,718	$ 3,114,597

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

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

	For the Years Ended December 31,		
(Thousands of Dollars)	2013	2012	2011
Operating Revenues	$ 935,402	$ 988,013	$ 1,013,003
Operating Expenses:			
Purchased Power, Fuel and Transmission	269,754	319,253	327,905
Operations and Maintenance	267,797	263,234	278,153
Depreciation	91,581	87,602	76,167
Amortization of Regulatory Assets/(Liabilities), Net	(20,387)	(24,086)	25,383
Amortization of Rate Reduction Bonds	19,748	56,645	53,389
Energy Efficiency Programs	14,494	14,245	12,917
Taxes Other Than Income Taxes	67,196	66,025	58,985
Total Operating Expenses	710,183	782,918	832,899
Operating Income	225,219	205,095	180,104
Interest Expense:			
Interest on Long-Term Debt	44,370	46,228	36,832
Interest on Rate Reduction Bonds	(154)	2,687	6,276
Other Interest	1,960	1,313	1,039
Interest Expense	46,176	50,228	44,147
Other Income, Net	3,455	3,008	14,255
Income Before Income Tax Expense	182,498	157,875	150,212
Income Tax Expense	71,101	60,993	49,945
Net Income	$ 111,397	$ 96,882	$ 100,267

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	2013	2012	2011
Net Income	$ 111,397	$ 96,882	$ 100,267
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	1,162	1,162	(10,260)
Changes in Unrealized Gains/(Losses) on Other Securities	(54)	13	29
Changes in Funded Status of Pension, SERP and PBOP Benefit Plans	(3)	2	-
Other Comprehensive Income/(Loss), Net of Tax	1,105	1,177	(10,231)

Comprehensive Income	$	112,502	$	98,059	$	90,036

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock		Capital Surplus,	Retained	Accumulated Other Comprehensive	Total Common Stockholder's
(Thousands of Dollars, Except Stock Information)	Stock	Amount	Paid In	Earnings	Income/(Loss)	Equity
Balance as of January 1, 2011	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
Net Income				111,397		111,397
Dividends on Common Stock				(68,000)		(68,000)
Allocation of Benefits - ESOP			859			859
Other Comprehensive Income					1,105	1,105
Balance as of December 31, 2013	301	$ -	$ 701,911	$ 438,515	$ (8,550)	$ 1,131,876

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

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

	For the Years Ended December 31,		
(Thousands of Dollars)	2013	2012	2011
Operating Activities:			
Net Income	$ 111,397	$ 96,882	$ 100,267
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	91,581	87,602	76,167
Deferred Income Taxes	75,693	58,552	75,628
Pension, SERP and PBOP Expense	26,846	26,312	27,298
Pension and PBOP Contributions	(112,964)	(96,880)	(121,178)
Regulatory (Under)/Over Recoveries, Net	(8,481)	(183)	6,079
Amortization of Regulatory (Liabilities)/Assets, Net	(20,387)	(24,086)	25,383
Amortization of Rate Reduction Bonds	19,748	56,645	53,389
Settlements of Cash Flow Hedge Instruments	-	-	(18,072)
Other	16,079	11,205	(13,923)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	2,412	(84)	7,833
Fuel, Materials and Supplies	(33,391)	25,897	(9,873)
Taxes Receivable/Accrued, Net	26,462	(9,752)	5,139
Accounts Payable	2,632	(15,248)	(4,517)
Other Current Assets and Liabilities, Net	(9,520)	13,436	(4,915)
Net Cash Flows Provided by Operating Activities	188,107	230,298	204,705
Investing Activities:			
Investments in Property, Plant and Equipment	(186,009)	(203,902)	(241,772)
Decrease/(Increase) in Notes Receivable from Affiliate	-	55,900	(55,900)
Decrease in Special Deposits	22,040	4,200	2,223
Other Investing Activities	(88)	(135)	(134)
Net Cash Flows Used in Investing Activities	(164,057)	(143,937)	(295,583)
Financing Activities:			
Cash Dividends on Common Stock	(68,000)	(90,674)	(58,828)
Increase/(Decrease) in Short-Term Debt	23,200	-	(30,000)
Issuance of Long-Term Debt	250,000	-	282,000
Retirements of Long-Term Debt	(198,235)	-	(119,800)

Retirements of Rate Reduction Bonds	(29,294)	(56,074)	(52,879)
Increase/(Decrease) in Notes Payable to Affiliate	-	63,300	(47,900)
Capital Contributions from NU Parent	-	-	120,030
Other Financing Activities	(4,084)	(476)	(4,248)
Net Cash Flows (Used in)/Provided by Financing Activities	(26,413)	(83,924)	88,375
Net (Decrease)/Increase in Cash	(2,363)	2,437	(2,503)
Cash - Beginning of Year	2,493	56	2,559
Cash - End of Year	$ 130	$ 2,493	$ 56

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 financial statements of Western Massachusetts Electric Company (WMECO or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company s internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of 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* (1992 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, 2013.

February 25, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of Western Massachusetts Electric Company (the "Company") as of December 31, 2013 and 2012 and the related statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 2013. 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 financial statements present fairly, in all material respects, the financial position of Western Massachusetts Electric Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, 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 financial statements taken as a whole presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut

February 25, 2014

102

WESTERN MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2013	2012
ASSETS		
Current Assets:		
Cash	$ -	$ 1
Receivables, Net	49,018	47,297
Accounts Receivable from Affiliated Companies	47,607	164
Unbilled Revenues	16,562	16,192
Taxes Receivable	432	15,513
Regulatory Assets	43,024	42,370
Marketable Securities	26,628	27,352
Prepayments and Other Current Assets	10,479	7,963
Total Current Assets	193,750	156,852
Property, Plant and Equipment, Net	1,381,060	1,290,498
Deferred Debits and Other Assets:		
Regulatory Assets	146,088	221,752
Marketable Securities	31,243	30,342
Other Long-Term Assets	40,679	23,625
Total Deferred Debits and Other Assets	218,010	275,719
Total Assets	$ 1,792,820	$ 1,723,069

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2013	2012
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ -	$ 31,900
Long-Term Debt - Current Portion	-	55,000
Accounts Payable	62,961	68,141
Accounts Payable to Affiliated Companies	9,230	7,103
Accrued Interest	7,525	8,304
Regulatory Liabilities	19,858	21,037
Accumulated Deferred Income Taxes	13,098	8,404
Counterparty Deposits	7,688	751
Other Current Liabilities	20,629	15,754
Total Current Liabilities	140,989	216,394
Rate Reduction Bonds	-	9,352
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	396,933	303,111
Regulatory Liabilities	13,873	9,686
Accrued Pension	-	24,215
Accrued SERP and PBOP	3,911	11,884
Other Long-Term Liabilities	28,619	40,148
Total Deferred Credits and Other Liabilities	443,336	389,044
Capitalization:		
Long-Term Debt	629,389	550,270
Common Stockholder's Equity:		
Common Stock	10,866	10,866
Capital Surplus, Paid In	390,743	390,412
Retained Earnings	181,014	160,577
Accumulated Other Comprehensive Loss	(3,517)	(3,846)
Common Stockholder's Equity	579,106	558,009
Total Capitalization	1,208,495	1,108,279
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 1,792,820	$ 1,723,069

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2013	2012	2011
Operating Revenues	$ 472,724	$ 441,164	$ 417,315
Operating Expenses:			
Purchased Power and Transmission	147,059	136,086	161,480
Operations and Maintenance	96,194	97,031	80,241
Depreciation	37,568	29,971	26,455
Amortization of Regulatory Assets/(Liabilities), Net	(3,206)	410	4,492
Amortization of Rate Reduction Bonds	7,780	17,632	16,523
Energy Efficiency Programs	39,524	27,802	21,804
Taxes Other Than Income Taxes	28,458	21,458	17,957
Total Operating Expenses	353,377	330,390	328,952
Operating Income	119,347	110,774	88,363
Interest Expense:			
Interest on Long-Term Debt	23,625	23,462	20,023
Interest on Rate Reduction Bonds	177	1,229	2,335
Other Interest	1,049	1,943	1,254
Interest Expense	24,851	26,634	23,612
Other Income, Net	3,310	2,503	1,489
Income Before Income Tax Expense	97,806	86,643	66,240
Income Tax Expense	37,368	32,140	23,186
Net Income	$ 60,438	$ 54,503	$ 43,054

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

STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 60,438	$ 54,503	$ 43,054
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	338	338	(4,108)
Changes in Unrealized Gains/(Losses) on Other Securities	(9)	2	5
Other Comprehensive Income/(Loss), Net of Tax	329	340	(4,103)
Comprehensive Income	$ 60,767	$ 54,843	$ 38,951

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock		Capital Surplus,	Retained	Accumulated Other Comprehensive	Total Common Stockholder's
(Thousands of Dollars, Except Stock Information)	Stock	Amount	Paid In	Earnings	Income/(Loss)	Equity
Balance as of January 1, 2011	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
Net Income				60,438		60,438
Dividends on Common Stock				(40,001)		(40,001)
Allocation of Benefits - ESOP			331			331
Other Comprehensive Income					329	329
Balance as of December 31, 2013	434,653	$ 10,866	$ 390,743	$ 181,014	$ (3,517)	$ 579,106

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2013	2012	2011
Operating Activities:			
Net Income	$ 60,438	$ 54,503	$ 43,054
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	37,568	29,971	26,455
Deferred Income Taxes	87,028	53,942	23,056
Regulatory Over/(Under) Recoveries, Net	8,458	(19,152)	3,328
Amortization of Regulatory (Liabilities)/Assets, Net	(3,206)	410	4,492
Amortization of Rate Reduction Bonds	7,780	17,632	16,523
Settlement of Cash Flow Hedge Instrument	-	-	(6,859)
Other	3,381	(3,954)	(586)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(53,292)	(8,896)	(7,263)
Materials and Supplies	865	(2,882)	331
Taxes Receivable/Accrued, Net	19,840	(8,311)	5,084
Accounts Payable	7,456	(19,297)	12,956
Other Current Assets and Liabilities, Net	2,491	581	3,824
Net Cash Flows Provided by Operating Activities	178,807	94,547	124,395
Investing Activities:			
Investments in Property, Plant and Equipment	(128,786)	(264,175)	(237,996)
Proceeds from Sales of Marketable Securities	70,778	79,769	125,157
Purchases of Marketable Securities	(71,390)	(80,529)	(125,453)
Decrease/(Increase) in Notes Receivable from Affiliate	-	11,000	(11,000)
Other Investing Activities	7,401	(28)	(1,919)
Net Cash Flows Used in Investing Activities	(121,997)	(253,963)	(251,211)
Financing Activities:			
Cash Dividends on Common Stock	(40,001)	(9,432)	(26,305)
Issuance of Long-Term Debt	80,000	150,000	100,000
Retirements of Long-Term Debt	(55,000)	(53,800)	-
(Decrease)/Increase in Notes Payable to Affiliate	(31,900)	31,900	(20,400)
Retirements of Rate Reduction Bonds	(9,352)	(17,540)	(16,433)

Capital Contributions from NU Parent	-	50,000	91,812
Other Financing Activities	(558)	8,288	(1,858)
Net Cash Flows (Used in)/Provided by Financing Activities	(56,811)	159,416	126,816
Net Decrease in Cash	(1)	-	-
Cash - Beginning of Year	1	1	1
Cash - End of Year	$ -	$ 1	$ 1

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

NORTHEAST UTILITIES AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY

NSTAR ELECTRIC COMPANY AND SUBSIDIARY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

COMBINED NOTES TO 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 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. On April 10, 2012, NU acquired NSTAR and its subsidiaries. NU's wholly owned regulated utility subsidiaries consist of CL&P, NSTAR Electric, PSNH, WMECO, Yankee Gas and NSTAR Gas. NU provides energy delivery service to approximately 3.6 million electric and natural gas customers through these 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, WMECO and NSTAR Gas, and the NHPUC 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: NUSCO, RRR, Renewable Properties, Inc., a wholly-owned subsidiary of NUTV, and Properties, Inc., a wholly-owned subsidiary of PSNH, 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. Hopkinton, a subsidiary of NU, provides natural gas liquefaction and storage services to NSTAR Gas. As of December 31, 2013, NU Enterprises primary business consisted of NGS operation and maintenance agreements, E.S. Boulos Company, an electrical contractor based in Maine, and NSTAR Communications, Inc., an unregulated telecommunications subsidiary.

B.

Basis of Presentation

The consolidated financial statements of NU, NSTAR Electric and PSNH include the accounts of each of their respective subsidiaries. Intercompany transactions have been eliminated in consolidation. The accompanying consolidated financial statements of NU, NSTAR Electric and PSNH and the financial statements of CL&P and WMECO are herein collectively referred to as the "financial statements."

The preparation of the 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NU's consolidated financial information includes NSTAR and its subsidiaries results of operations beginning April 10, 2012. The information disclosed for NSTAR Electric represents its results of operations for each of the years ended December 31, 2013, 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 consolidates CYAPC and YAEC as CL&P s, NSTAR Electric s, PSNH s and WMECO s combined ownership interest in each of these entities is greater than 50 percent. Intercompany transactions between CL&P, NSTAR Electric, PSNH and WMECO and the CYAPC and YAEC companies have been eliminated in consolidation of the NU financial statements. For CL&P, NSTAR Electric, PSNH and WMECO, the investments 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.

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 reclassifications of prior year data were made in the accompanying balance sheets for NU, NSTAR Electric, PSNH and WMECO and the statements of cash flows for all companies presented. These reclassifications were made to conform to the current year presentation.

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 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 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 statements of income and cash flows represents net income prior to apportionment to noncontrolling interests, which is represented by dividends on preferred stock of CL&P and NSTAR Electric.

C.

Accounting Standards

Recently Adopted Accounting Standards: In the first quarter of 2013, NU, CL&P, NSTAR Electric, PSNH and WMECO, adopted the following Financial Accounting Standards Board s (FASB) final Accounting Standards Updates (ASU) relating to additional disclosure requirements:

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (AOCI): The ASU does not change existing guidance on which items should be reclassified out of AOCI but requires additional disclosures about the components of AOCI and the amount of reclassification adjustments to be presented in one location in the footnotes. The ASU was effective beginning in the first quarter of 2013 and was applied prospectively. For further information, see Note 15, "Accumulated Other Comprehensive Income/(Loss)," to the financial statements. The ASU did not affect the calculation of net income, comprehensive income or EPS and did not have an impact on financial position, results of operations or cash flows.

Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities: Clarifies the scope of the offsetting disclosure requirements under GAAP and applies to derivative instruments. The ASU was effective beginning in the first quarter of 2013 with retrospective application. For further information, see Note 5, "Derivative Instruments," to the financial statements. The ASU did not have an impact on financial position, results of operations or cash flows.

Accounting Standards Issued but not Yet Adopted: In July 2013, the FASB issued a final ASU effective January 1, 2014, requiring presentation of certain unrecognized tax benefits as reductions to deferred tax assets. The ASU is required to be implemented prospectively on January 1, 2014. Implementation of this guidance will have an immaterial impact on the balance sheets and no impact on the 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 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 amounts. 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. The DPU allows WMECO to also recover in rates amounts associated with certain uncollectible hardship accounts receivable. As of December 31, 2013, CL&P, WMECO and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $67.3 million, $5.5 million and $8.4 million, respectively, with the corresponding under recovery of bad debt expense recorded as Regulatory Assets or Other Long-Term Assets as these amounts are probable of recovery. As of December 31, 2012, these amounts totaled $65.2 million, $4.7 million and $6.4 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 balance sheets, was as follows:

	As of December 31,	
(Millions of Dollars)	**2013**	**2012**
NU	$ 171.3	$ 165.5
CL&P	82.0	77.6
NSTAR Electric	41.7	44.1
PSNH	7.4	6.8
WMECO	10.0	8.5

F.

Fuel, Materials and Supplies and Allowance Inventory

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

As of December 31, 2013, NU had $139.5 million ($74.2 million at PSNH) of fuel and $163.7 million ($54.5 million at PSNH) of materials and supplies. As of December 31, 2012, NU had $109 million ($39.6 million at PSNH) of fuel and $158.7 million ($55.7 million at PSNH) of materials and supplies.

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, 2013 and 2012, PSNH had $0.2 million and $0.4 million, respectively, of short-term SO_2, CO_2, and NO_x emissions allowances classified as Fuel, Materials and Supplies 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 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 $0.3 million, $0.4 million and $5.1 million for the years ended December 31, 2013, 2012, and 2011, respectively, which were included in Purchased Power, Fuel and Transmission on the statements of income. These costs or benefits are recovered from or refunded to customers through energy supply revenues. For the year ended December 31, 2013, PSNH received $6.8 million in proceeds from the auction of allowances, resulting in a net benefit of $6.5 million.

G.

Restricted Cash and Other Deposits

As of December 31, 2013, NU and CL&P had $1.7 million and $1.4 million, respectively, of restricted cash relating to amounts held in escrow, which were included in Prepayments and Other Current Assets on the balance sheets. As of December 31, 2012, these amounts were $3.3 million, $1.3 million and $1.7 million for NU, CL&P and PSNH, respectively.

As of December 31, 2013 and 2012, NU had $17.9 million ($9 million of which related to NSTAR Electric) and $14.6 million, respectively, of cash collateral posted not subject to master netting agreements, primarily with ISO-NE, which were included in Prepayments and Other Current Assets on the balance sheets.

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 for the payment of RRBs. As of December 31, 2013, there were no deposits related to these RRB subsidiaries as NSTAR Electric, PSNH and WMECO made their final payments in the first half of 2013 and these deposit balances were fully utilized.

H.

Fair Value Measurements

Fair value measurement guidance is applied to derivative contracts that are not elected or designated as "normal purchases or normal sales" (normal) and to the marketable securities held in trusts. Fair value measurement guidance is also applied to investment valuations used to calculate the funded status of pension and PBOP plans 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:

110

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 financial statements.

I.

Derivative Accounting

Many of the Regulated companies' contracts for the purchase and sale of energy or energy-related products are derivatives. 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. For the Regulated companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivative contracts, as costs are recovered from, or refunded to, customers in future rates.

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 exception, and determination of the fair value of derivative contracts. All of these judgments can have a significant impact on the financial statements.

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 fair value of derivative contracts 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 balance sheets. Changes in the fair value of derivative contracts are recorded as regulatory assets or liabilities and do not impact net income.

For further information regarding derivative contracts, see Note 5, "Derivative Instruments," to the 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. Upon consummation of the merger with NSTAR, NSTAR Electric's ownership interests 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 beginning April 10, 2012. The investments 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, as well as MYAPC, 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, 2013 and 2012 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 balance sheets, were as follows:

	As of December 31,	
(Millions of Dollars)	**2013**	**2012**
CL&P	$ 1.2	$ 1.4
NSTAR Electric	0.5	0.6
PSNH	0.3	0.3
WMECO	0.3	0.4

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

Other Investments: As of December 31, 2013 and 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. These investments are accounted for under the equity method of accounting. NU s investment totaled $5.1 million and $6 million as of December 31, 2013 and 2012, respectively, and NSTAR Electric's investment totaled $2 million and $2.3 million as of December 31, 2013 and 2012, respectively. As of December 31, 2013 and 2012, NU also had an equity ownership interest of $9.8 million and $6.8 million in an energy investment fund, respectively.

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

K.

Revenues

Regulated Companies: The Regulated companies' retail revenues are based on rates approved by their respective 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 the costs to provide service to their customers, including a return on investment. 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. WMECO has 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 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 statements of income and are assets on the 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 recovered through FERC approved formula rates. 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 that recover the costs of transmission and other transmission-related services for CL&P, PSNH and WMECO and Schedule 21 - NSTAR rate schedules that recover costs of transmission and other transmission-related services for NSTAR Electric. The RNS rate, administered by ISO-NE and billed to all New England transmission load, including CL&P, NSTAR Electric, PSNH and WMECO's distribution 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. Schedule 21 - NU and Schedule 21 - NSTAR rates, administered by NU, recovers the remainder of the transmission revenue requirements. 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 transmission revenue requirements in accordance with the ISO-NE Tariff. RNS, Schedule 21 - NU and Schedule 21 - NSTAR rates provide for the annual reconciliation and recovery or refund of estimated costs to actual costs. The financial impacts of differences between actual and estimated 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 included in Purchased Power, Fuel and Transmission on the statements of income were as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2013**	**2012**	**2011**
NU - Natural Gas and Fuel [1]	$ 466.5	$ 346.8	$ 307.9
PSNH - Fuel	104.8	103.4	115.9

[1] NSTAR Gas natural gas costs were included in NU beginning April 10, 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 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)	**2013**	**2012 [1]**	**2011**
AFUDC:			
Borrowed Funds	$ 4.1	$ 5.3	$ 11.8
Equity Funds	7.1	6.8	22.5
Total	$ 11.2	$ 12.1	$ 34.3
Average AFUDC Rate	2.7%	3.7%	7.3%

[1] NSTAR amounts were included in NU beginning April 10, 2012.

	For the Years Ended December 31,		
	2013	**2012**	**2011**
(Millions of Dollars,	**NSTAR**	**NSTAR**	**NSTAR**

except percentages)	**CL&P**	**Electric**	**PSNH**	**WMECO**	**CL&P**	**Electric**	**PSNH**	**WMECO**	**CL&P**	**Electric**	**PSNH**	**WMECO**
AFUDC:												
Borrowed Funds	$ 2.2	$ 0.5	$ 0.5	$ 0.5	$ 2.5	$ 0.3	$ 1.6	$ 0.5	$ 3.3	$ 0.2	$ 7.1	$ 0.5
Equity Funds	2.9	-	0.2	1.0	1.9	-	1.9	1.0	6.0	-	13.2	1.0
Total	$ 5.1	$ 0.5	$ 0.7	$ 1.5	$ 4.4	$ 0.3	$ 3.5	$ 1.5	$ 9.3	$ 0.2	$ 20.3	$ 1.5
Average AFUDC Rate	3.7%	0.5%	1.1%	6.1%	3.6%	0.4%	5.9%	6.8%	8.3%	0.3%	7.1%	7.4%

The Regulated companies' average AFUDC rate is based on a FERC-prescribed formula 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 statements of income primarily consist of investment income/(loss), interest income, AFUDC related to equity funds, and equity in earnings. Investment income/(loss) primarily related to the NU supplemental benefit trust. For further information, see Note 6, "Marketable Securities," to the financial statements. For further information on AFUDC related to equity funds, see Note 1M, "Summary of Significant Accounting Policies Allowance for Funds Used During Construction," to the financial statements. For further information on equity in earnings, see Note 1J, "Summary of Significant Accounting Policies Equity Method Investments," to the financial statements.

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 statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2013**	**2012**	**2011**
NU	$ 144.1	$ 135.0	$ 137.8
CL&P	128.2	120.7	121.6

Certain sales taxes are also collected by NU's companies that serve customers in Connecticut and Massachusetts as agents for state and local governments and are recorded on a net basis with no impact on the statements of income.

P.

Supplemental Cash Flow Information

NU	As of and For the Years Ended December 31,		
(Millions of Dollars)	**2013**	**2012** [1]	**2011**
Cash Paid/(Received) During the Year for:			
Interest, Net of Amounts Capitalized	$ 343.3	$ 356.5	$ 256.3
Income Taxes	50.0	(12.8)	(76.6)
Non-Cash Investing Activities:			
Plant Additions Included in Accounts Payable (As of)	193.1	160.6	168.5

[1] NSTAR amounts were included in NU beginning April 10, 2012.

	As of and For the Years Ended December 31,											
	2013				**2012**				**2011**			
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**
Cash Paid/(Received) During the Year for:												
Interest, Net of Amounts Capitalized	$ 131.6	$ 75.8	$ 43.3	$ 25.8	$ 129.4	$ 94.6	$ 49.8	$ 25.8	$ 136.6	$ 96.1	$ 49.3	$ 22.1
Income Taxes	55.0	163.4	(30.1)	(69.0)	(42.0)	88.1	14.7	(8.4)	(27.5)	(62.2)	(29.0)	(4.9)
Non-Cash Investing Activities:												
Plant Additions Included in Accounts Payable (As of)	51.4	57.0	34.9	19.5	42.8	50.0	16.8	30.0	32.7	34.3	51.1	61.3

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, NU's service company, provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. RRR, Renewable Properties, Inc. and Properties, Inc., three other NU subsidiaries, construct, acquire or lease some of the property and facilities used by NU's companies.

As of both December 31, 2013 and 2012, 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 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 balance sheets included $64.2 million and $70.2 million in Payable to Affiliated Companies as of December 31, 2013 and 2012, respectively. These amounts related to payments received from affiliates as a result of NSTAR Electric s role as the acting sponsor of the NSTAR Pension Plan.

Included in the CL&P, NSTAR Electric, PSNH and WMECO balance sheets as of December 31, 2013 and 2012 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.

R.

Severance Benefits

During 2013, NU recorded severance benefit expenses of $9.7 million in connection with the partial outsourcing of information technology functions made as part of ongoing post-merger integration. As of December 31, 2013, the severance accrual totaled $14.7 million and was included in Other Current Liabilities on the balance sheet.

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 and its subsidiaries became wholly-owned subsidiaries of NU.

NSTAR was a holding company engaged through its subsidiaries in the energy delivery business serving electric and natural gas distribution customers in Massachusetts. 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.

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

*

Included 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 was included in the purchase price as it represented 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 was 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 included 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 were judgmental in nature. These estimates and assumptions included the timing and amounts of projected future cash flows and discount rates reflecting risk inherent in future cash flows.

In accordance with accounting guidance for business combinations, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. The allocation of the purchase price was as follows:

(Millions of Dollars)

Current Assets	$	739
Property Plant and Equipment, Net		5,155
Goodwill		3,232
Other Long-Term Assets, excluding Goodwill		2,103
Current Liabilities		(1,330)
Long-Term Liabilities		(2,723)
Long-Term Debt and Other Long-Term Obligations		(2,099)
Noncontrolling Interest		(39)
Total Purchase Price	$	5,038

The goodwill from the merger with NSTAR of $3.2 billion was allocated to NU's reporting units based on their estimated 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.

	For the Years Ended December 31,			
(Pro forma amounts in millions, except per share amounts)		**2012**		**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 merger settlement agreements described below, with the following aggregate after-tax impacts:

	For the Years Ended December 31,			
(Millions of Dollars)	**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 merger settlement agreements with the Massachusetts Attorney General and the DOER. 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 merger settlement agreement with both the Connecticut Attorney General and the Connecticut Office of Consumer Counsel. 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 merger settlement agreements that were recognized in 2012 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

Goodwill: In accordance with the accounting standards, goodwill is not subject to amortization. However, goodwill is subject to fair value-based rules for measuring impairment, and resulting write-downs, if any, are charged to Operating Expenses. These accounting standards require that goodwill be reviewed at least annually for impairment and whenever facts or circumstances indicate that there may be an impairment. 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 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 financial statements. Accordingly, the goodwill resulting from the merger was 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.

Prior to the merger with NSTAR, the only reporting unit that maintained goodwill was the Natural Gas Distribution reportable segment related to the acquisition of the parent of Yankee Gas in 2000. This goodwill was recorded at Yankee Gas. The goodwill balance at Yankee Gas as of December 31, 2013 and 2012 was $0.3 billion.

NU completed its annual goodwill impairment test for each of its reporting units as of October 1, 2013 and determined that no impairment exists. There were no events subsequent to October 1, 2013 that indicated impairment of goodwill.

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

(Billions of Dollars)	**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

There were no changes to the goodwill balance or the allocation of goodwill for the year ended December 31, 2013.

3.

REGULATORY ACCOUNTING

The rates charged to the customers of NU's Regulated companies are designed to collect each company's costs to provide service, including a return on investment. Therefore, the accounting policies of the Regulated companies reflect the application of accounting guidance for entities with rate-regulated operations and reflect the effects of the rate-making process.

Management believes it is probable that each of the Regulated companies will recover their respective investments in long-lived assets, including regulatory assets. If management were to determine that it could no longer apply the accounting guidance applicable to rate-regulated enterprises to any of the Regulated companies' operations, or that management could not conclude it is probable that costs would be recovered from customers 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)	**2013**		**2012**	
Benefit Costs	$	1,240.2	$	2,452.1
Derivative Liabilities		638.0		885.6
Goodwill		525.9		537.6
Storm Restoration Costs		589.6		547.7
Income Taxes, Net		626.2		516.2
Securitized Assets		-		232.6
Contractual Obligations - Yankee Companies		154.2		217.6
Buy Out Agreements for Power Contracts		70.2		92.9
Regulatory Tracker Mechanisms		323.4		190.1
Other Regulatory Assets		126.8		165.0
Total Regulatory Assets		4,294.5		5,837.4
Less: Current Portion		535.8		705.0
Total Long-Term Regulatory Assets	$	3,758.7	$	5,132.4

	As of December 31,							
	2013				**2012**			
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**
Benefit Costs	$ 297.7	$ 496.7	$ 100.6	$ 57.3	$ 563.2	$ 781.2	$ 223.7	$ 116.0
Derivative Liabilities	630.4	7.7	-	-	866.2	14.9	-	3.0
Goodwill	-	451.5	-	-	-	461.5	-	-
	397.8	109.3	43.7	38.8	413.9	55.8	34.5	43.5

Storm Restoration Costs								
Income Taxes, Net	415.5	84.0	40.3	43.7	367.5	47.1	36.2	31.0
Securitized Assets	-	-	-	-	-	205.1	19.7	7.8
Contractual Obligations - Yankee Companies	19.8	6.2	-	4.5	64.0	22.8	-	14.9
Buy Out Agreements for Power Contracts	-	64.7	5.5	-	-	85.9	7.0	-
Regulatory Tracker Mechanisms	8.0	169.5	83.3	32.6	12.2	71.4	49.3	31.9
Other Regulatory Assets	44.8	49.7	38.1	12.2	57.3	46.3	43.6	16.1
Total Regulatory Assets	1,814.0	1,439.3	311.5	189.1	2,344.3	1,792.0	414.0	264.2
Less: Current Portion	150.9	204.1	92.2	43.0	185.9	347.1	62.9	42.4
Total Long-Term Regulatory Assets	$ 1,663.1	$ 1,235.2	$ 219.3	$ 146.1	$ 2,158.4	$ 1,444.9	$ 351.1	$ 221.8

Regulatory Costs in Other Long-Term Assets: The Regulated companies had $65.1 million ($7.3 million for CL&P, $33.4 million for NSTAR Electric, and $10.1 million for WMECO) and $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) of additional regulatory costs as of December 31, 2013 and 2012, respectively, that were included in Other Long-Term Assets on the balance sheets. These amounts represent incurred costs for which recovery has not yet been specifically approved by the applicable regulatory agency. However, based on regulatory policies or past precedent on similar costs, management believes it is probable that these costs will ultimately be approved and recovered from customers in rates.

The PSNH balance as of December 31, 2012 primarily related to storm restoration costs incurred for Tropical Storm Irene, the October 2011 snowstorm and Storm Sandy that met the NHPUC criteria for cost deferral and recovery. Refer to the "*Storm Restoration Costs*" section in this Note for further discussion. The NSTAR Electric balance as of December 31, 2013 and 2012 primarily related to costs deferred in connection with the basic service bad debt adder. See Note 12G, "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 related to their regulatory assets. For certain regulatory assets, the carrying cost recovered includes an equity return component. This equity return, which is not recorded on the balance sheets, totaled $1.9 million and $2.5 million for CL&P and $33.1 million and $21.8 million for PSNH as of December 31, 2013 and 2012, respectively. These carrying costs will be recovered from customers 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. Because the Regulated companies recover the retiree benefit costs from customers through rates, regulatory assets are recorded in lieu of a charge to Accumulated Other Comprehensive Income/(Loss) to reflect the liability that is recognized for the funded status of the pension and other postretirement plans and is remeasured annually. Regulatory accounting was also applied to the portions of NU's service company costs that support the Regulated companies, as these amounts are also recoverable. CL&P, NSTAR Electric, PSNH and WMECO do not collect carrying charges on these benefit costs regulatory assets.

CL&P, NSTAR Electric, PSNH and WMECO recover benefit costs related to their distribution and transmission operations from customers in rates as allowed by their applicable regulatory commissions. NSTAR Electric and WMECO each recover their qualified pension and postretirement expenses related to distribution operations through rate reconciling mechanisms that fully track the change in net pension and postretirement expenses each year. 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, 2013 and 2012, these balances were $379.9 million and $366.8 million of the total benefit costs regulatory asset, respectively.

Derivative Liabilities: Regulatory assets recorded as an offset to derivative liabilities relate to the fair value of contracts used to purchase energy and energy-related products that will be recovered from customers in future rates. See Note 5, "Derivative Instruments," to the financial statements for further information. These assets are excluded from rate base and are being recovered as the actual settlements occur over the duration of the contracts.

Goodwill: The goodwill regulatory asset originated from the transaction that created NSTAR in 1999. This regulatory asset is currently being amortized and recovered from customers in rates without a carrying charge over a 40-year period (as of December 31, 2013, there were 26 years of amortization remaining).

Storm Restoration Costs: The storm restoration cost deferrals relate to costs incurred at CL&P, NSTAR Electric, PSNH and WMECO that each company expects to recover 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 as follows:

.

Connecticut - qualifying storm restoration costs must exceed $5 million for a storm to be declared a major storm;

.

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; and

.

New Hampshire - For a storm to be declared a major storm: (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.

Once a storm is declared major, all qualifying expenses prudently incurred during storm restoration efforts are deferred and recovered from customers.

In addition to storm restoration costs, PSNH is allowed recovery of prudently incurred storm pre-staging costs in accordance with NHPUC regulation.

In 2013, 2012 and 2011, CL&P, NSTAR Electric, PSNH and WMECO experienced significant storms, including Tropical Storm Irene, the October 2011 snowstorm, Storm Sandy, and the February 2013 blizzard. As a result of these storm events, each Company suffered extensive damage to its distribution and transmission systems resulting in customer outages, which required the incurrence of costs to repair damage and restore customer service. The storm restoration cost regulatory asset balance at CL&P, NSTAR Electric, PSNH and WMECO reflects costs incurred for major storm events. Management believes the storm restoration costs were prudent and meet the criteria for specific cost recovery in Connecticut, Massachusetts and New Hampshire and as a result, are probable of recovery.

Storm Filings: Each electric utility is seeking recovery of its deferred storm restoration costs through its applicable regulatory recovery process.

On February 3, 2014, the PURA issued a draft decision on CL&P s request to recover storm restoration costs associated with five major storms, all of which occurred in 2011 and 2012. In its draft decision, the PURA approved recovery of $365 million of deferred storm restoration costs and ordered CL&P to capitalize approximately $18 million of the deferred storm restoration costs as utility plant, which will be included in depreciation expense in future rate proceedings. PURA will allow recovery of the $365 million with carrying charges in CL&P s distribution rates over a six-year period beginning December 1, 2014. The remaining costs were either disallowed or are probable of recovery in future rates and did not have a material impact on CL&P s financial position, results of operations or cash flows.

On December 30, 2013, the DPU approved NSTAR Electric s request to recover storm restoration costs, plus carrying costs, related to Tropical Storm Irene and the October 2011 snowstorm. The DPU approved recovery of $34.2 million of the $38 million requested costs. NSTAR Electric will recover these costs, plus carrying costs, in its distribution rates over a five-year period beginning on January 1, 2014.

On June 27, 2013, the NHPUC approved an increase to PSNH s distribution rates effective July 1, 2013, which included a $5 million increase to the current level of funding for the major storm cost reserve. The major storm cost reserve is used to offset the storm restoration cost regulatory asset.

On August 30, 2013, WMECO submitted its 2013 Annual Storm Reserve Recovery Cost Adjustment (SRRCA) filing to begin recovering the restoration costs associated with the October 2011 snowstorm and Storm Sandy. On December 20, 2013, the DPU approved the 2013 Annual SRRCA filing for effect on January 1, 2014, subject to further review and reconciliation.

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 financial statements.

Securitized Assets: NSTAR Electric's securitized regulatory asset balance primarily included costs related to purchase power contract divestitures and certain costs related to NSTAR Electric s former generation business that were recovered with a return through the transition charge and amounted to $186.1 million as of December 31, 2012. These costs were fully recovered from customers in 2013.

The securitized regulatory asset balance as of December 31, 2012 also included proceeds received from the issuance of RRBs at NSTAR Electric, PSNH and WMECO that were used to buy out or buy down purchase power contracts. The collateralized amounts reflected as securitized regulatory assets for NSTAR Electric, PSNH and WMECO as of December 31, 2012 were $14.1 million, $19.7 million and $7.8 million, respectively. As of December 31, 2013, NSTAR Electric's, PSNH's and WMECO's RRBs were fully redeemed and the related regulatory assets were fully recovered from customers.

Contractual Obligations - Yankee Companies: CL&P, NSTAR Electric, PSNH and WMECO are responsible for their proportionate share of the remaining costs of the CYAPC, YAEC and MYAPC nuclear facilities, including decommissioning. A portion of these amounts was recorded as a regulatory asset. Amounts for CL&P are earning a return and are being recovered through the CTA. Amounts for NSTAR Electric and WMECO are being recovered without a return through the transition charge. Amounts for PSNH were fully recovered in 2006. As a result of NU's consolidation of CYAPC and YAEC, NU's regulatory asset balance also includes the regulatory assets of CYAPC and YAEC, which totalled $129.8 million and $214 million as of December 31, 2013 and 2012, respectively. 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.

Buy Out Agreements for Power Contracts: NSTAR Electric's balance represents the contract termination liability related to certain purchase power contract buy out agreements that were executed in 2004. The contracts termination payments occur through September 2016 and are collected from customers through NSTAR Electric s transition charge over the same period. Therefore, NSTAR Electric does not earn a return on this regulatory asset. 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 Mechanisms: The Regulated companies approved rates are designed to recover their incurred costs to provide service to customers. The Regulated companies are permitted to recover certain of their costs on a fully-reconciling basis through regulatory commission-approved tracking mechanisms. The difference between the costs incurred (or the rate recovery allowed) and the actual revenues is recorded as regulatory assets (for undercollections) or regulatory liabilities (for overcollections) to be included in future customer rates each year. Carrying charges are recorded on all material regulatory tracker mechanisms.

CL&P, NSTAR Electric, PSNH and WMECO each recover the costs associated with the procurement of energy, transmission related costs from FERC-approved transmission tariffs, energy efficiency programs, low income assistance programs, and restructuring and stranded costs as a result of deregulation, on a fully reconciling basis. Energy procurement costs at PSNH include the costs related to its generating stations.

WMECO s distribution revenue is decoupled from its customer sales volume. WMECO reconciles its annual base distribution rate recovery to a pre-established level of baseline distribution delivery service revenue. Any difference between the allowed level of distribution revenue and the actual amount incurred in a calendar year is adjusted through rates in the following year.

Other Regulatory Assets: Other Regulatory Assets primarily include asset retirement obligations, environmental remediation costs, losses associated with the reacquisition or redemption of long-term debt and various other items, partially offset by purchase price adjustments recorded as Regulatory Assets in connection with the merger with NSTAR. The ARO costs associated with the depreciation of the Regulated companies' ARO assets and accretion of the ARO liabilities are recorded as regulatory assets. 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.

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

NU	**As of December 31,**	
(Millions of Dollars)	**2013**	**2012**
Cost of Removal	$ 435.1	$ 440.8
Regulatory Tracker Mechanisms	151.2	95.1
AFUDC Transmission	68.1	70.0
Other Regulatory Liabilities	52.9	68.4
Total Regulatory Liabilities	707.3	674.3
Less: Current Portion	204.3	134.1
Total Long-Term Regulatory Liabilities	$ 503.0	$ 540.2

	As of December 31,							
	2013				**2012**			
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**
Cost of Removal	$ 29.1	$ 250.0	$ 49.7	$ -	$ 44.2	$ 240.3	$ 51.2	$ -
Regulatory Tracker Mechanisms	95.6	21.9	21.6	21.1	39.1	14.4	20.4	19.0
AFUDC Transmission	54.7	4.1	-	9.3	56.6	4.1	-	9.3
Other Regulatory Liabilities	8.4	31.1	1.0	3.4	16.5	32.9	3.8	2.4
Total Regulatory Liabilities	187.8	307.1	72.3	33.8	156.4	291.7	75.4	30.7
Less: Current Portion	94.0	54.0	20.6	19.9	32.1	47.5	23.0	21.0
Total Long-Term Regulatory Liabilities	$ 93.8	$ 253.1	$ 51.7	$ 13.9	$ 124.3	$ 244.2	$ 52.4	$ 9.7

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: AFUDC was recorded by CL&P and WMECO 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, 2013, 50 percent of which was recorded as a regulatory liability to reflect rate base recovery for 50 percent of the CWIP as a result of FERC-approved transmission incentives.

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 investments in utility property, plant and equipment by asset category:

NU	**As of December 31,**	
(Millions of Dollars)	**2013**	**2012**
Distribution - Electric	$ 11,950.2	$ 11,438.2
Distribution - Natural Gas	2,425.9	2,274.2
Transmission	6,412.5	5,541.1
Generation	1,152.3	1,146.6
Electric and Natural Gas Utility	21,940.9	20,400.1
Other [(1)]	508.7	429.3
Property, Plant and Equipment, Gross	22,449.6	20,829.4
Less: Accumulated Depreciation		
Electric and Natural Gas Utility	(5,387.0)	(5,065.1)
Other	(196.2)	(171.5)
Total Accumulated Depreciation	(5,583.2)	(5,236.6)
Property, Plant and Equipment, Net	16,866.4	15,592.8
Construction Work in Progress	709.8	1,012.2
Total Property, Plant and Equipment, Net	$ 17,576.2	$ 16,605.0

(1)

These assets represent unregulated property and are primarily comprised of building improvements at RRR, software, hardware and equipment at NUSCO and telecommunications assets at NSTAR Communications, Inc.

	As of December 31,							
	2013				2012			
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**
Distribution	$ 4,930.7	$ 4,694.7	$ 1,608.2	$ 756.6	$ 4,691.3	$ 4,539.9	$ 1,520.1	$ 724.2
Transmission	3,071.9	1,772.3	695.7	826.4	2,796.1	1,529.7	599.2	583.7
Generation	-	-	1,131.2	21.1	-	-	1,125.5	21.1
Property, Plant and Equipment, Gross	8,002.6	6,467.0	3,435.1	1,604.1	7,487.4	6,069.6	3,244.8	1,329.0
Less: Accumulated Depreciation	(1,804.1)	(1,631.3)	(1,021.8)	(271.5)	(1,698.1)	(1,540.1)	(954.0)	(252.1)
Property, Plant and Equipment, Net	6,198.5	4,835.7	2,413.3	1,332.6	5,789.3	4,529.5	2,290.8	1,076.9
Construction Work in Progress	252.8	208.2	54.3	48.5	363.7	205.8	61.7	213.6
Total Property, Plant and Equipment, Net	$ 6,451.3	$ 5,043.9	$ 2,467.6	$ 1,381.1	$ 6,153.0	$ 4,735.3	$ 2,352.5	$ 1,290.5

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 over the lives of the plant assets 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)	**2013**	**2012**	**2011**

NU	2.8	2.5	2.6
CL&P	2.5	2.5	2.4
NSTAR Electric	2.9	2.8	3.0
PSNH	3.0	3.0	2.9
WMECO	2.9	3.3	2.9

The following table summarizes average useful lives of depreciable assets:

	Average Depreciable Life				
(Years)	**NU**	**CL&P**	**NSTAR Electric**	**PSNH**	**WMECO**
Distribution	36.1	42.0	32.9	32.7	29.8
Transmission	43.0	39.6	47.2	42.3	49.5
Generation	32.2	-	-	32.4	25.0
Other	14.6	-	-	-	-

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 and nonderivative contracts.

Many of the derivative contracts meet the definition of, and are designated as, normal and qualify for accrual accounting under the applicable accounting guidance. The costs and benefits of derivative contracts that meet the definition of normal are recognized in Operating Expenses or Operating Revenues on the statements of income, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not designated as normal are recorded at fair value as current or long-term Derivative Assets or Derivative Liabilities on the balance sheets. For the Regulated companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivatives, as costs are recovered from, or refunded to, customers in their respective energy supply rates. For NU's unregulated wholesale marketing contracts that expired on December 31, 2013, changes in fair values of derivatives were included in Net 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, on the 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 amount recorded as current or long-term derivative asset or liability:

	As of December 31, 2013					
(Millions of Dollars)	**Commodity Supply and Price Risk Management**		**Netting [(1)]**		**Net Amount Recorded as Derivative Asset/(Liability)**	
Current Derivative Assets:						
Level 2:						
Other [(1)]	$	1.9	$	(0.3)	$	1.6
Level 3:						
CL&P [(1)]		17.1		(9.8)		7.3
NSTAR Electric		1.2		-		1.2
WMECO		0.1		-		0.1
Total Current Derivative Assets	$	20.3	$	(10.1)	$	10.2
Long-Term Derivative Assets:						
Level 2:						
- Other	$	0.2	$	-	$	0.2
Level 3:						
CL&P [(1)]		113.6		(42.2)		71.4
WMECO		2.6		-		2.6
Total Long-Term Derivative Assets	$	116.4	$	(42.2)	$	74.2
Current Derivative Liabilities:						
Level 3:						
CL&P	$	(92.2)	$	-	$	(92.2)
NSTAR Electric		(1.5)		-		(1.5)
Total Current Derivative Liabilities	$	(93.7)	$	-	$	(93.7)
Long-Term Derivative Liabilities:						
Level 3:						
CL&P	$	(617.1)	$	-	$	(617.1)
NSTAR Electric		(7.0)		-		(7.0)
Total Long-Term Derivative Liabilities	$	(624.1)	$	-	$	(624.1)

	As of December 31, 2012					
(Millions of Dollars)	**Commodity Supply and Price Risk Management**		**Netting [(1)]**		**Net Amount Recorded as Derivative Asset/(Liability)**	
Current Derivative Assets:						
Level 2:						
- Other	$	0.2	$	-	$	0.2

Level 3:						
CL&P [(1)]		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 [(1)]	$	159.7	$	(69.1)	$	90.6
Total Long-Term Derivative Assets	$	159.7	$	(69.1)	$	90.6
Current Derivative Liabilities:						
Level 2:						
- Other [(1)] [(2)]	$	(19.9)	$	0.6	$	(19.3)
Level 3:						
CL&P						