CONNECTICUT LIGHT & POWER CO
Form 10-Q
August 05, 2011

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended June 30, 2011

OR

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

For the transition period from ____________ to ____________

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

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 registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) 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 whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (check one):

	Large Accelerated Filer	**Accelerated Filer**	**Non-accelerated Filer**
Northeast Utilities	ü		
The Connecticut Light and Power Company			ü
Public Service Company of New Hampshire			ü
Western Massachusetts Electric Company			ü

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

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

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 July 30, 2011
Northeast Utilities	
Common shares, $5.00 par value	176,893,612 shares
The Connecticut Light and Power Company	
Common stock, $10.00 par value	6,035,205 shares
Public Service Company of New Hampshire	
Common stock, $1.00 par value	301 shares
Western Massachusetts Electric Company	
Common stock, $25.00 par value	434,653 shares

Northeast Utilities holds all of the 6,035,205 shares, 301 shares, and 434,653 shares of the outstanding common stock of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company, respectively.

Public Service Company of New Hampshire and Western Massachusetts Electric Company each meet the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q, and each is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) of Form 10-Q.

GLOSSARY OF TERMS

The following is a glossary of abbreviations or acronyms that are found in this report.

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS:

Boulos	E.S. Boulos Company
CL&P	The Connecticut Light and Power Company
HWP	HWP Company, formerly the Holyoke Water Power Company
NGS	Northeast Generation Services Company and subsidiaries
NPT	Northern Pass Transmission LLC, a jointly owned limited liability company, held by NUTV and NSTAR Transmission Ventures, Inc. on a 75 percent and 25 percent basis, respectively
NUTV	NU Transmission Ventures, Inc.
NU or the Company	Northeast Utilities and subsidiaries
NU Enterprises	NU Enterprises, Inc., the parent company of Select Energy, NGS, NGS Mechanical, Select Energy Contracting, Inc. and Boulos
NUSCO	Northeast Utilities Service Company
NU parent and other companies	NU parent and other companies is comprised of NU parent, NUSCO and other subsidiaries, including HWP, RRR (a real estate subsidiary), and the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, and Yankee Energy Financial Services Company)
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's Regulated companies, comprised of the electric distribution and transmission segments of CL&P, PSNH and WMECO, the generation activities of PSNH and WMECO, Yankee Gas, a natural gas local distribution company, and NPT
RRR	The Rocky River Realty Company
Select Energy	Select Energy, Inc.
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS:

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

OTHER:

2010 Form 10-K	The Northeast Utilities and subsidiaries 2010 combined Annual Report on Form 10-K as filed with the SEC
2010 Healthcare Act	Patient Protection and Affordable Care Act
2010 Tax Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act
AOCI	Accumulated Other Comprehensive Income/(Loss)
AFUDC	Allowance For Funds Used During Construction
C&LM	Conservation and Load Management
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
FASB	Financial Accounting Standards Board
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	Giga-watt Hours
HG&E	Holyoke Gas and Electric, a municipal department of the town of Holyoke, MA
HQ	Hydro-Québec, a corporation wholly-owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High voltage direct current
Hydro Renewable Energy	H.Q. Hydro Renewable Energy, Inc., a wholly-owned subsidiary of Hydro-Québec
IASB	International Accounting Standards Board
IPP	Independent Power Producers
ISO-NE	ISO New England, Inc., the New England Independent System Operator
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
KV	Kilovolt
KWh	Kilowatt-Hours
LNG	Liquefied natural gas
LOC	Letter of Credit
LRS	Last resort service
MGP	Manufactured Gas Plant
Money Pool	Northeast Utilities Money Pool
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
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
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
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segments excluding the wholesale transmission segment
RMR	Reliability Must Run
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
SERP	Supplemental Executive Retirement Plan
SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement

UI	The United Illuminating Company
VIE	Variable interest entity
WWL Project	The construction of a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of Yankee Gas' LNG plant
Yankee Companies	Connecticut Yankee Atomic Power Company, Yankee Atomic Electric Company and Maine Yankee Atomic Power Company

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

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Western Massachusetts Electric Company and Subsidiary

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NORTHEAST UTILITIES AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)	June 30, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 15,107	$ 23,395
Receivables, Net	470,921	523,644
Unbilled Revenues	154,370	208,834
Taxes Receivable	49,130	89,638
Fuel, Materials and Supplies	230,754	244,043
Regulatory Assets	242,137	238,699
Marketable Securities	74,680	78,306
Prepayments and Other Current Assets	100,763	100,441
Total Current Assets	1,337,862	1,507,000
Property, Plant and Equipment, Net	9,863,789	9,567,726
Deferred Debits and Other Assets:		
Regulatory Assets	2,656,093	2,756,580
Goodwill	287,591	287,591
Marketable Securities	58,154	51,201
Derivative Assets	86,730	123,242
Other Long-Term Assets	152,127	179,261
Total Deferred Debits and Other Assets	3,240,695	3,397,875
Total Assets	$ 14,442,346	$ 14,472,601

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)	June 30, 2011	December 31, 2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 137,000	$ 267,000
Long-Term Debt - Current Portion	336,991	66,286
Accounts Payable	373,799	417,285
Obligations to Third Party Suppliers	74,522	74,659
Accrued Taxes	104,125	107,067
Accrued Interest	69,582	74,740
Regulatory Liabilities	152,956	99,403
Derivative Liabilities	105,583	71,501
Other Current Liabilities	121,469	167,206
Total Current Liabilities	1,476,027	1,345,147
Rate Reduction Bonds	147,252	181,572
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,777,163	1,636,750
Regulatory Liabilities	273,909	339,655
Derivative Liabilities	884,283	909,668
Accrued Pension	798,467	802,195
Other Long-Term Liabilities	696,040	695,915
Total Deferred Credits and Other Liabilities	4,429,862	4,384,183
Capitalization:		
Long-Term Debt	4,356,052	4,632,866
Noncontrolling Interest in Consolidated Subsidiary:		
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Equity:		
Common Shareholders' Equity:		
Common Shares	979,884	978,909
Capital Surplus, Paid In	1,785,907	1,777,592
Retained Earnings	1,546,493	1,452,777
Accumulated Other Comprehensive Loss	(45,791)	(43,370)
Treasury Stock	(351,387)	(354,732)
Common Shareholders' Equity	3,915,106	3,811,176
Noncontrolling Interests	1,847	1,457
Total Equity	3,916,953	3,812,633
Total Capitalization	8,389,205	8,561,699

Total Liabilities and Capitalization	$	14,442,346	$	14,472,601

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(Thousands of Dollars, Except Share Information)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating Revenues	$ 1,047,481	$ 1,111,426	$ 2,282,732	$ 2,450,845
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	340,300	442,230	814,409	1,045,578
Other Operating Expenses	262,818	206,664	514,796	454,937
Maintenance	78,825	66,817	146,589	112,454
Depreciation	73,637	79,075	147,588	157,731
Amortization of Regulatory Assets, Net	17,262	8,893	51,669	566
Amortization of Rate Reduction Bonds	17,086	54,997	34,367	114,567
Taxes Other Than Income Taxes	79,419	74,406	167,823	160,005
Total Operating Expenses	869,347	933,082	1,877,241	2,045,838
Operating Income	178,134	178,344	405,491	405,007
Interest Expense:				
Interest on Long-Term Debt	57,044	58,522	114,444	115,791
Interest on Rate Reduction Bonds	2,293	5,633	4,871	12,324
Other Interest	2,897	3,042	1,468	6,343
Interest Expense	62,234	67,197	120,783	134,458
Other Income, Net	7,334	1,552	17,647	9,608
Income Before Income Tax Expense	123,234	112,699	302,355	280,157
Income Tax Expense	44,515	39,351	108,052	119,209
Net Income	78,719	73,348	194,303	160,948
Net Income Attributable to Noncontrolling Interests	1,441	1,402	2,870	2,792
Net Income Attributable to Controlling Interests	$ 77,278	$ 71,946	$ 191,433	$ 158,156
Basic and Diluted Earnings Per Common Share	$ 0.44	$ 0.41	$ 1.08	$ 0.90
Dividends Declared Per Common Share	$ 0.28	$ 0.26	$ 0.55	$ 0.51

Weighted Average Common Shares Outstanding:				
Basic	177,347,374	176,571,189	177,267,791	176,460,476
Diluted	177,626,992	176,736,532	177,553,995	176,637,003

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(Thousands of Dollars)	2011	2010
Operating Activities:		
Net Income	$ 194,303	$ 160,948
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	9,374	17,176
Depreciation	147,588	157,731
Deferred Income Taxes	95,293	37,850
Pension and PBOP Expense, Net of PBOP Contributions	51,324	25,529
Pension Contribution	(19,200)	-
Regulatory Overrecoveries, Net	40,434	21,569
Amortization of Regulatory Assets, Net	51,669	566
Amortization of Rate Reduction Bonds	34,367	114,567
Derivative Assets and Liabilities	(9,272)	(5,640)
Other	(7,192)	(29,707)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	80,696	34,703
Fuel, Materials and Supplies	12,992	52,024
Taxes Receivable/Accrued	48,933	(3,856)
Accounts Payable	(23,981)	(53,480)
Other Current Assets and Liabilities	(20,633)	3,799
Net Cash Flows Provided by Operating Activities	686,695	533,779
Investing Activities:		
Investments in Property, Plant and Equipment	(468,526)	(442,404)
Proceeds from Sales of Marketable Securities	72,369	95,452
Purchases of Marketable Securities	(73,564)	(96,546)
Proceeds from Sale of Assets	46,841	-
Other Investing Activities	(4,828)	(4,369)
Net Cash Flows Used in Investing Activities	(427,708)	(447,867)
Financing Activities:		
Cash Dividends on Common Shares	(97,207)	(90,194)
Cash Dividends on Preferred Stock	(2,779)	(2,779)
(Decrease)/Increase in Short-Term Debt	(130,000)	57,000
Issuance of Long-Term Debt	122,000	145,000
Retirements of Long-Term Debt	(124,086)	(4,286)
Retirements of Rate Reduction Bonds	(34,320)	(128,600)
Other Financing Activities	(883)	(230)
Net Cash Flows Used in Financing Activities	(267,275)	(24,089)
Net (Decrease)/Increase in Cash and Cash Equivalents	(8,288)	61,823

Cash and Cash Equivalents - Beginning of Period		23,395		26,952
Cash and Cash Equivalents - End of Period	$	15,107	$	88,775

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)		June 30, 2011		December 31, 2010
ASSETS				
Current Assets:				
Cash	$	5,078	$	9,762
Receivables, Net		295,688		317,530
Accounts Receivable from Affiliated Companies		3,678		822
Notes Receivable from Affiliated Companies		24,125		-
Unbilled Revenues		87,486		116,392
Taxes Receivable		24,121		48,360
Regulatory Assets		163,917		157,530
Materials and Supplies		73,063		63,811
Accumulated Deferred Income Taxes		21,366		-
Prepayments and Other Current Assets		20,180		27,466
Total Current Assets		718,702		741,673
Property, Plant and Equipment, Net		5,655,205		5,586,504
Deferred Debits and Other Assets:				
Regulatory Assets		1,668,232		1,721,416
Derivative Assets		82,902		115,870
Other Long-Term Assets		96,981		89,729
Total Deferred Debits and Other Assets		1,848,115		1,927,015
Total Assets	$	8,222,022	$	8,255,192

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)	June 30, 2011	December 31, 2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ -	6,225
Long-Term Debt - Current Portion	62,000	62,000
Accounts Payable	173,098	204,868
Accounts Payable to Affiliated Companies	46,911	53,207
Obligations to Third Party Suppliers	67,026	68,692
Accrued Taxes	94,841	92,061
Accrued Interest	38,774	42,548
Regulatory Liabilities	102,869	75,716
Derivative Liabilities	83,442	46,781
Other Current Liabilities	49,042	46,209
Total Current Liabilities	718,003	698,307
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,165,269	1,068,344
Regulatory Liabilities	141,635	206,394
Derivative Liabilities	863,292	883,091
Accrued Pension	36,364	42,486
Other Long-Term Liabilities	315,912	321,793
Total Deferred Credits and Other Liabilities	2,522,472	2,522,108
Capitalization:		
Long-Term Debt	2,521,457	2,521,102
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Common Stockholder's Equity:		
Common Stock	60,352	60,352
Capital Surplus, Paid In	1,606,014	1,605,275
Retained Earnings	680,010	734,561
Accumulated Other Comprehensive Loss	(2,486)	(2,713)
Common Stockholder's Equity	2,343,890	2,397,475
Total Capitalization	4,981,547	5,034,777
Total Liabilities and Capitalization	$ 8,222,022	$ 8,255,192

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended		Six Months Ended	
(Thousands of Dollars)	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
Operating Revenues	$ 608,013	$ 707,917	$ 1,281,695	$ 1,502,897
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	207,163	290,553	462,533	653,374
Other Operating Expenses	139,308	120,293	273,570	255,106
Maintenance	41,869	32,821	82,651	54,660
Depreciation	38,442	47,944	77,917	95,469
Amortization of Regulatory Assets, Net	13,705	20,640	33,049	22,311
Amortization of Rate Reduction Bonds	-	38,924	-	82,207
Taxes Other Than Income Taxes	52,727	50,585	111,193	108,114
Total Operating Expenses	493,214	601,760	1,040,913	1,271,241
Operating Income	114,799	106,157	240,782	231,656
Interest Expense:				
Interest on Long-Term Debt	33,430	33,630	66,758	67,262
Interest on Rate Reduction Bonds	-	2,243	-	5,275
Other Interest	868	1,334	(2,708)	3,197
Interest Expense	34,298	37,207	64,050	75,734
Other Income, Net	2,058	745	6,663	5,678
Income Before Income Tax Expense	82,559	69,695	183,395	161,600
Income Tax Expense	29,924	25,610	66,423	69,102
Net Income	$ 52,635	$ 44,085	$ 116,972	$ 92,498

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(Thousands of Dollars)	Six Months Ended June 30, 2011	2010
Operating Activities:		
Net Income	$ 116,972	$ 92,498
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	2,252	5,494
Depreciation	77,917	95,469
Deferred Income Taxes	60,425	11,624
Pension and PBOP Expense, Net of PBOP Contributions	9,868	3,602
Regulatory Overrecoveries, Net	24,142	30,459
Amortization of Regulatory Assets, Net	33,049	22,311
Amortization of Rate Reduction Bonds	-	82,207
Other	(17,752)	(29,444)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	34,192	15,679
Materials and Supplies	(11,761)	4,767
Taxes Receivable/Accrued	31,797	12,694
Accounts Payable	(12,078)	(38,735)
Other Current Assets and Liabilities	9,968	22,341
Net Cash Flows Provided by Operating Activities	358,991	330,966
Investing Activities:		
Investments in Property, Plant and Equipment	(201,966)	(191,667)
(Increase)/Decrease in NU Money Pool Lending	(24,125)	97,775
Proceeds from Sale of Assets	46,841	-
Other Investing Activities	(6,489)	1,463
Net Cash Flows Used in Investing Activities	(185,739)	(92,429)
Financing Activities:		
Cash Dividends on Common Stock	(168,744)	(145,992)
Cash Dividends on Preferred Stock	(2,779)	(2,779)
(Decrease)/Increase in NU Money Pool Borrowings	(6,225)	15,625
Retirements of Rate Reduction Bonds	-	(96,267)
Other Financing Activities	(188)	(170)
Net Cash Flows Used in Financing Activities	(177,936)	(229,583)
Net (Decrease)/Increase in Cash	(4,684)	8,954
Cash - Beginning of Period	9,762	45
Cash - End of Period	$ 5,078	$ 8,999

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)		June 30, 2011		December 31, 2010
ASSETS				
Current Assets:				
Cash	$	2,413	$	2,559
Receivables, Net		87,958		105,070
Accounts Receivable from Affiliated Companies		646		858
Unbilled Revenues		44,358		48,691
Taxes Receivable		2,796		12,564
Fuel, Materials and Supplies		106,371		116,074
Regulatory Assets		38,705		39,215
Prepayments and Other Current Assets		29,879		20,098
Total Current Assets		313,126		345,129
Property, Plant and Equipment, Net		2,135,883		2,053,281
Deferred Debits and Other Assets:				
Regulatory Assets		375,551		395,203
Other Long-Term Assets		59,932		85,508
Total Deferred Debits and Other Assets		435,483		480,711
Total Assets	$	2,884,492	$	2,879,121

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)	June 30, 2011	December 31, 2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 22,000	$ 30,000
Notes Payable to Affiliated Companies	43,800	47,900
Accounts Payable	71,278	85,324
Accounts Payable to Affiliated Companies	19,854	20,007
Accrued Interest	8,463	10,231
Regulatory Liabilities	22,369	8,365
Derivative Liabilities	9,097	12,834
Other Current Liabilities	25,371	36,726
Total Current Liabilities	222,232	251,387
Rate Reduction Bonds	112,195	138,247
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	336,877	314,996
Regulatory Liabilities	57,104	58,631
Accrued Pension	253,824	261,096
Other Long-Term Liabilities	100,518	91,952
Total Deferred Credits and Other Liabilities	748,323	726,675
Capitalization:		
Long-Term Debt	838,304	836,365
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	599,917	579,577
Retained Earnings	367,186	347,471
Accumulated Other Comprehensive Loss	(3,665)	(601)
Common Stockholder's Equity	963,438	926,447
Total Capitalization	1,801,742	1,762,812
Total Liabilities and Capitalization	$ 2,884,492	$ 2,879,121

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(Thousands of Dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating Revenues	$ 240,191	$ 238,322	$ 509,661	$ 496,890
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	69,342	83,253	156,474	187,024
Other Operating Expenses	54,226	56,073	110,647	119,199
Maintenance	29,859	25,625	48,563	41,627
Depreciation	18,122	16,020	36,030	31,988
Amortization of Regulatory Assets/(Liabilities), Net	2,465	(11,627)	18,032	(17,322)
Amortization of Rate Reduction Bonds	13,004	12,246	26,139	24,637
Taxes Other Than Income Taxes	15,234	13,348	28,902	26,426
Total Operating Expenses	202,252	194,938	424,787	413,579
Operating Income	37,939	43,384	84,874	83,311
Interest Expense:				
Interest on Long-Term Debt	8,317	9,268	16,941	18,780
Interest on Rate Reduction Bonds	1,676	2,516	3,570	5,237
Other Interest	408	185	346	364
Interest Expense	10,401	11,969	20,857	24,381
Other Income/(Loss), Net	4,361	(197)	8,820	2,215
Income Before Income Tax Expense	31,899	31,218	72,837	61,145
Income Tax Expense	10,234	9,602	23,708	23,719
Net Income	$ 21,665	$ 21,616	$ 49,129	$ 37,426

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(Thousands of Dollars)	2011	2010
Operating Activities:		
Net Income	$ 49,129	$ 37,426
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	3,303	4,282
Depreciation	36,030	31,988
Deferred Income Taxes	20,773	15,486
Pension and PBOP Expense, Net of PBOP Contributions	11,112	9,606
Pension Contribution	(15,175)	-
Regulatory Overrecoveries/(Underrecoveries), Net	726	(5,459)
Amortization of Regulatory Assets/(Liabilities), Net	18,032	(17,322)
Amortization of Rate Reduction Bonds	26,139	24,637
Insurance Proceeds	-	10,000
Other	(2,545)	(21,057)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	12,844	3,338
Fuel, Materials and Supplies	11,915	30,714
Taxes Receivable/Accrued	9,767	2,057
Accounts Payable	(8,611)	(12,305)
Other Current Assets and Liabilities	(16,885)	(4,558)
Net Cash Flows Provided by Operating Activities	156,554	108,833
Investing Activities:		
Investments in Property, Plant and Equipment	(111,459)	(141,709)
Other Investing Activities	1,928	(4,367)
Net Cash Flows Used in Investing Activities	(109,531)	(146,076)
Financing Activities:		
Cash Dividends on Common Stock	(29,414)	(25,292)
Decrease in Short-Term Debt	(8,000)	-
Issuance of Long-Term Debt	122,000	-
Retirements of Long-Term Debt	(119,800)	-
Decrease in NU Money Pool Borrowings	(4,100)	(18,900)
Capital Contributions from NU Parent	20,000	115,428
Retirements of Rate Reduction Bonds	(26,052)	(24,568)
Other Financing Activities	(1,803)	(114)
Net Cash Flows (Used in)/Provided by Financing Activities	(47,169)	46,554

Net (Decrease)/Increase in Cash		(146)		9,311
Cash - Beginning of Period		2,559		1,974
Cash - End of Period	$	2,413	$	11,285

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)		June 30, 2011		December 31, 2010
ASSETS				
Current Assets:				
Cash	$	1	$	1
Receivables, Net		37,948		37,585
Accounts Receivable from Affiliated Companies		585		505
Unbilled Revenues		14,539		16,578
Taxes Receivable		8		7,346
Materials and Supplies		4,062		3,664
Regulatory Assets		19,454		19,531
Marketable Securities		28,033		33,194
Prepayments and Other Current Assets		1,624		1,968
Total Current Assets		106,254		120,372
Property, Plant and Equipment, Net		908,654		817,146
Deferred Debits and Other Assets:				
Regulatory Assets		191,939		207,584
Marketable Securities		29,085		23,860
Other Long-Term Assets		29,931		30,597
Total Deferred Debits and Other Assets		250,955		262,041
Total Assets	$	1,265,863	$	1,199,559

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)		June 30, 2011		December 31, 2010
LIABILITIES AND CAPITALIZATION				
Current Liabilities:				
Notes Payable to Banks	$	20,000	$	-
Notes Payable to Affiliated Companies		28,100		20,400
Accounts Payable		65,344		48,344
Accounts Payable to Affiliated Companies		10,832		7,848
Accrued Interest		6,736		6,787
Regulatory Liabilities		16,579		7,959
Accumulated Deferred Income Taxes		2,818		5,902
Other Current Liabilities		10,957		9,842
Total Current Liabilities		161,366		107,082
Rate Reduction Bonds		35,057		43,325
Deferred Credits and Other Liabilities:				
Accumulated Deferred Income Taxes		229,399		218,063
Regulatory Liabilities		16,904		15,048
Other Long-Term Liabilities		55,834		58,169
Total Deferred Credits and Other Liabilities		302,137		291,280
Capitalization:				
Long-Term Debt		400,362		400,288
Common Stockholder's Equity:				
Common Stock		10,866		10,866
Capital Surplus, Paid In		253,360		248,044
Retained Earnings		103,741		98,757
Accumulated Other Comprehensive Loss		(1,026)		(83)
Common Stockholder's Equity		366,941		357,584
Total Capitalization		767,303		757,872
Total Liabilities and Capitalization	$	1,265,863	$	1,199,559

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(Thousands of Dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating Revenues	$ 98,390	$ 92,473	$ 205,074	$ 192,680
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	32,617	36,720	72,821	80,352
Other Operating Expenses	26,376	23,067	52,606	46,293
Maintenance	4,214	5,367	8,986	9,909
Depreciation	6,625	5,868	12,963	11,821
Amortization of Regulatory Assets/(Liabilities), Net	1,796	(721)	1,196	(2,290)
Amortization of Rate Reduction Bonds	4,082	3,827	8,228	7,722
Taxes Other Than Income Taxes	4,203	4,080	8,745	8,163
Total Operating Expenses	79,913	78,208	165,545	161,970
Operating Income	18,477	14,265	39,529	30,710
Interest Expense:				
Interest on Long-Term Debt	4,722	4,726	9,476	8,607
Interest on Rate Reduction Bonds	617	874	1,301	1,811
Other Interest	121	57	257	183
Interest Expense	5,460	5,657	11,034	10,601
Other Income, Net	242	161	981	765
Income Before Income Tax Expense	13,259	8,769	29,476	20,874
Income Tax Expense	5,088	3,520	11,339	9,966
Net Income	$ 8,171	$ 5,249	$ 18,137	$ 10,908

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(Thousands of Dollars)	2011	2010
Operating Activities:		
Net Income	$ 18,137	$ 10,908
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	1,860	3,304
Depreciation	12,963	11,821
Deferred Income Taxes	7,004	5,061
Regulatory Overrecoveries/(Underrecoveries), Net	8,754	(8,181)
Amortization of Regulatory Assets/(Liabilities), Net	1,196	(2,290)
Amortization of Rate Reduction Bonds	8,228	7,722
Other	(2,034)	(3,136)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	405	(1,762)
Materials and Supplies	(398)	(767)
Taxes Receivable/Accrued	9,523	(80)
Accounts Payable	1,021	605
Other Current Assets and Liabilities	(281)	393
Net Cash Flows Provided by Operating Activities	66,378	23,598
Investing Activities:		
Investments in Property, Plant and Equipment	(76,898)	(46,354)
Proceeds from Sales of Marketable Securities	57,746	69,196
Purchases of Marketable Securities	(57,888)	(69,350)
Increase in NU Money Pool Lending	-	(22,000)
Other Investing Activities	(792)	(170)
Net Cash Flows Used in Investing Activities	(77,832)	(68,678)
Financing Activities:		
Cash Dividends on Common Stock	(13,153)	(7,441)
Increase in Short-Term Debt	20,000	-
Issuance of Long-Term Debt	-	95,000
Increase/(Decrease) in NU Money Pool Borrowings	7,700	(136,100)
Retirements of Rate Reduction Bonds	(8,268)	(7,765)
Capital Contributions from NU Parent	5,186	102,600
Other Financing Activities	(11)	(1,214)
Net Cash Flows Provided by Financing Activities	11,454	45,080
Net Change in Cash	-	-

Cash - Beginning of Period		1		1
Cash - End of Period	$	1	$	1

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

NORTHEAST UTILITIES AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

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

1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A.

Proposed Merger with NSTAR

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

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

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

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. NU has received regulatory approvals from the FCC, the FERC and the Maine Public Utilities Commission and the applicable Hart-Scott-Rodino waiting period has expired. The DPUC and the NHPUC have issued decisions stating they do not have jurisdiction over the merger. NU is awaiting approval from the DPU and the Nuclear Regulatory Commission.

B.

Presentation

Pursuant to the rules and regulations of the SEC, certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted. The accompanying unaudited condensed consolidated financial statements should be read in conjunction with the entirety of this combined Quarterly Report on Form 10-Q, the first quarter 2011 combined Quarterly Report on Form 10-Q, and the 2010 combined Annual Report on Form 10-K of NU, CL&P, PSNH, and WMECO, which was filed with the SEC (NU 2010 Form 10-K). The accompanying unaudited condensed consolidated financial statements contain, in the opinion of management, all adjustments (including normal, recurring adjustments) necessary to present fairly NU's and the above companies' financial positions as of June 30, 2011 and December 31, 2010, the results of operations for the three and six months ended June 30, 2011 and 2010, and cash flows for the six months ended June 30, 2011 and 2010. The results of operations for the three months ended June 30, 2011 and 2010, and the results of operations and cash flows for the six months ended June 30, 2011 and 2010, are not necessarily indicative of the results expected for a full year.

The unaudited condensed consolidated financial statements of NU, CL&P, PSNH and WMECO include the accounts of all their respective subsidiaries. Intercompany transactions have been eliminated in consolidation.

The preparation of the unaudited condensed consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the unaudited condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

As of June 30, 2011, NU, CL&P, PSNH and WMECO have adjusted the presentation of Regulatory Assets and Liabilities to reflect the current portions, and related deferred tax amounts, as current assets and liabilities on the unaudited condensed consolidated balance sheets. Amounts as of December 31, 2010 have been reclassified to conform to the June 30, 2011 presentation. For additional information, see Note 2, "Regulatory Accounting," to the unaudited condensed consolidated financial statements.

Certain other reclassifications of prior period data were made in the accompanying unaudited condensed consolidated statements of cash flows for all companies presented. These reclassifications were made to conform to the current period's presentation.

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

C.

Accounting Standards Issued But Not Yet Adopted

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

D.

Restricted Cash

As of June 30, 2011, NU, CL&P, and PSNH had $15.9 million, $7.4 million, and $7 million, respectively, of restricted cash, primarily relating to amounts held in escrow related to property damage at CL&P and insurance proceeds on bondable property at PSNH, which were included in Prepayments and Other Current Assets on the accompanying unaudited condensed consolidated balance sheets. NU, CL&P, and PSNH had no restricted cash as of December 31, 2010.

E.

Provision for Uncollectible Accounts

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

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

(Millions of Dollars)		**As of June 30, 2011**		**As of December 31, 2010**
NU	$	38.2	$	39.8
CL&P		16.4		17.2
PSNH		7.5		6.8
WMECO		5.2		6.0

F.

Fair Value Measurements

NU, including CL&P, PSNH, and WMECO, applies fair value measurement guidance to all derivative contracts recorded at fair value and to the marketable securities held in the NU supplemental benefit trust and WMECO's spent nuclear fuel trust. Fair value measurement guidance is also applied to investment valuations used to calculate the funded status of NU's Pension and PBOP plans and non-recurring fair value measurements of NU's non-financial assets and liabilities.

Fair Value Hierarchy: In measuring fair value, NU uses observable market data when available and minimizes the use of unobservable inputs. Unobservable inputs are needed to value certain derivative contracts due to complexities in the terms of the contracts. Inputs used in fair value measurements are categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement. NU evaluates the classification of assets and liabilities measured at fair value on a quarterly basis, and NU's policy is to recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. The three levels of the fair value hierarchy are described below:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Inputs are quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs are observable.

Level 3 - Quoted market prices are not available. Fair value is derived from valuation techniques in which one or more significant inputs or assumptions are unobservable. Where possible, valuation techniques incorporate observable market inputs that can be validated to external sources such as industry exchanges, including prices of energy and energy-related products. Significant unobservable inputs are used in the valuations, including items such as energy and energy-related product prices in future years for which observable prices are not yet available, future contract quantities under full-requirements or supplemental sales contracts, and market volatilities. Items valued using these valuation techniques are classified according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, an item may be classified in Level 3 even though there may be some significant inputs that are readily observable.

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

G.

Allowance for Funds Used During Construction

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

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
(Millions of Dollars, except percentages)	NU	NU	NU	NU
AFUDC:				
Borrowed Funds	$ 3.3	$ 2.3	$ 6.5	$ 4.2
Equity Funds	6.3	3.8	11.9	6.9
Total	$ 9.6	$ 6.1	$ 18.4	$ 11.1
Average AFUDC Rate	7.8%	7.0%	7.4%	6.8%

	For the Three Months Ended					
	June 30, 2011			June 30, 2010		
(Millions of Dollars, except percentages)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
AFUDC:						
Borrowed Funds	$ 0.7	$ 2.3	$ 0.1	$ 0.7	$ 1.5	$ 0.1
Equity Funds	1.2	4.4	0.1	1.2	2.4	0.2
Total	$ 1.9	$ 6.7	$ 0.2	$ 1.9	$ 3.9	$ 0.3
Average AFUDC Rate	7.9%	7.7%	6.8%	8.0%	6.7%	6.7%

	For the Six Months Ended					
	June 30, 2011			June 30, 2010		
(Millions of Dollars, except percentages)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
AFUDC:						
Borrowed Funds	$ 1.5	$ 4.4	$ 0.1	$ 1.4	$ 2.6	$ 0.1
Equity Funds	2.7	7.8	0.2	2.5	4.2	0.2
Total	$ 4.2	$ 12.2	$ 0.3	$ 3.9	$ 6.8	$ 0.3
Average AFUDC Rate	8.0%	7.3%	7.0%	8.0%	6.5%	4.1%

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

AFUDC was recorded on 100 percent of CL&P's and WMECO's CWIP for their NEEWS projects through May 31, 2011, all of which was reserved as a regulatory liability to reflect rate base recovery for 100 percent of the CWIP as a result of FERC-approved transmission incentives. Effective June 1, 2011, FERC approved changes to the ISO-NE Tariff in order to include 100 percent of the NEEWS CWIP in regional rate base. As a result, CL&P and WMECO will no longer record AFUDC on NEEWS CWIP.

H.

Other Income, Net

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

I.

Other Taxes

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

	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars)	**June 30, 2011**	**June 30, 2010**	**June 30, 2011**	**June 30, 2010**
NU	$ 32.0	$ 33.1	$ 70.7	$ 72.0
CL&P	28.8	30.2	60.2	62.2

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

J. Supplemental Cash Flow Information

Non-cash investing activities include capital expenditures incurred but not yet paid as follows:

(Millions of Dollars)	**As of June 30, 2011**	**As of December 31, 2010**
NU	$ 109.4	$ 127.9
CL&P	19.4	46.2
PSNH	29.6	35.8
WMECO	39.7	21.2

Short-term borrowings of NU, including CL&P, PSNH, and WMECO, have original maturities of three months or less. Accordingly, borrowings and repayments are shown net on the unaudited condensed consolidated statements of cash flows.

2.

REGULATORY ACCOUNTING

The Regulated companies continue to be rate-regulated on a cost-of-service basis, therefore, the accounting policies of the Regulated companies conform to GAAP applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process.

Management believes it is probable that the Regulated companies will recover their respective investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning a return, except for the majority of deferred benefit cost assets, regulatory assets offsetting derivative liabilities, securitized regulatory assets and income tax regulatory assets, all of which are not in rate base.

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

	As of June 30, 2011		As of December 31, 2010	
(Millions of Dollars)	NU		NU	
Deferred Benefit Costs	$	1,036.1	$	1,094.2
Regulatory Assets Offsetting Derivative Liabilities		866.9		859.7
Securitized Assets		137.3		171.7
Income Taxes, Net		419.0		401.5
Unrecovered Contractual Obligations		112.4		123.2
Regulatory Tracker Deferrals		48.3		70.3
Storm Cost Deferrals		77.3		60.1
Asset Retirement Obligations		46.9		45.3
Losses on Reacquired Debt		22.3		21.5
Deferred Environmental Remediation Costs		39.8		36.8
Deferred Operation and Maintenance Costs		7.8		29.5
Other Regulatory Assets		84.1		81.5
Total Regulatory Assets	$	2,898.2	$	2,995.3
Less: Current Portion	$	242.1	$	238.7
Total Long-Term Regulatory Assets	$	2,656.1	$	2,756.6

	As of June 30, 2011						As of December 31, 2010					
(Millions of Dollars)	CL&P		PSNH		WMECO		CL&P		PSNH		WMECO	
Deferred Benefit Costs	$	445.6	$	145.9	$	91.2	$	471.8	$	152.6	$	96.0
Regulatory Assets Offsetting Derivative Liabilities		859.8		6.7		-		846.2		12.8		-
Securitized Assets		-		103.6		33.7		-		129.8		41.9
Income Taxes, Net		340.4		35.2		16.6		328.9		31.4		16.8
Unrecovered Contractual Obligations		89.6		-		22.8		97.9		-		25.3

Regulatory Tracker Deferrals		13.9		13.9		16.0		35.5		14.7		15.2
Storm Cost Deferrals		10.4		48.5		18.4		4.0		40.7		15.4
Asset Retirement Obligations		26.0		14.9		3.1		24.9		14.7		3.0
Losses on Reacquired Debt		11.1		9.5		0.3		11.2		8.4		0.4
Deferred Environmental Remediation Costs		-		9.7		-		-		9.7		-
Deferred Operation and Maintenance Costs		7.8		-		-		29.5		-		-
Other Regulatory Assets		27.5		26.4		9.3		29.0		19.6		13.1
Total Regulatory Assets	$	1,832.1	$	414.3	$	211.4	$	1,878.9	$	434.4	$	227.1
Less: Current Portion	$	163.9	$	38.7	$	19.5	$	157.5	$	39.2	$	19.5
Total Long-Term Regulatory Assets	$	1,668.2	$	375.6	$	191.9	$	1,721.4	$	395.2	$	207.6

Additionally, the Regulated companies had $4.4 million ($0.8 million for CL&P and $0.1 million for WMECO) and $37.5 million ($0.6 million for CL&P, $26.5 million for PSNH and $1.9 million for WMECO) of regulatory costs as of June 30, 2011 and December 31, 2010, respectively, which were included in Other Long-Term Assets on the accompanying unaudited condensed consolidated balance sheets. These amounts represent incurred costs that have not yet been approved for recovery by the applicable regulatory agency. Management believes these costs are probable of recovery in future cost-of-service regulated rates.

During June 2011, the NHPUC approved for recovery costs incurred for the February 2010 winter storm restorations and certain costs related to previously recognized tax benefits lost as a result of a provision in the 2010 Healthcare Act that eliminated the tax deductibility of actuarially equivalent Medicare Part D benefits for retirees. Both deferrals were previously recorded in Other Long-Term Assets. As of June 30, 2011, $10.9 million for the February 2010 wind storm costs and $7.2 million for the recovery of the future tax benefits lost as a result of the 2010 Healthcare Act were recorded as Regulatory Assets.

Major Storms: On June 1, 2011, a series of severe thunderstorms with high winds, including a tornado, struck portions of WMECO s service territory. The cost of restoring power, including rebuilding certain overhead electric distribution equipment and services, that was deferred for future recovery and recorded as a regulatory asset as of June 30, 2011 totaled $3.2 million. On June 9, 2011, another series of severe thunderstorms with high winds struck CL&P, PSNH and WMECO's service territories. The cost of restoration that was deferred for future recovery from customers and recorded as regulatory assets as of June 30, 2011 for CL&P and WMECO totaled $7.9 million and $1.2 million, respectively.

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

	As of June 30, 2011	As of December 31, 2010
(Millions of Dollars)	NU	NU
Cost of Removal	$ 186.7	$ 194.8
Regulatory Liabilities Offsetting Derivative Assets	-	38.1
Regulatory Tracker Deferrals	124.4	95.1
AFUDC Transmission Incentive	67.5	62.1
Pension Liability - Yankee Gas Acquisition	11.3	12.5
Overrecovered Spent Nuclear Fuel Costs and Contractual Obligations	14.6	14.6
Wholesale Transmission Overcollections	8.7	13.7
Other Regulatory Liabilities	13.7	8.2
Total Regulatory Liabilities	$ 426.9	$ 439.1
Less: Current Portion	$ 153.0	$ 99.4
Total Long-Term Regulatory Liabilities	$ 273.9	$ 339.7

	As of June 30, 2011			As of December 31, 2010		
(Millions of Dollars)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Cost of Removal	$ 72.8	$ 55.8	$ 9.3	$ 78.6	$ 57.3	$ 9.5
Regulatory Liabilities Offsetting Derivative Assets	-	-	-	38.1	-	-
Regulatory Tracker Deferrals	84.8	19.4	11.6	79.4	6.6	4.8
AFUDC Transmission Incentive	58.2	-	9.3	56.5	-	5.6
Overrecovered Spent Nuclear Fuel Costs and Contractual Obligations	14.6	-	-	14.6	-	-
Wholesale Transmission Overcollections	7.6	-	1.1	13.7	-	-
WMECO Provision For Rate Refunds	-	-	1.8	-	-	2.0
Other Regulatory Liabilities	6.5	4.3	0.4	1.2	3.1	1.1
Total Regulatory Liabilities	$ 244.5	$ 79.5	$ 33.5	$ 282.1	$ 67.0	$ 23.0
Less: Current Portion	$ 102.9	$ 22.4	$ 16.6	$ 75.7	$ 8.4	$ 8.0
Total Long-Term Regulatory Liabilities	$ 141.6	$ 57.1	$ 16.9	$ 206.4	$ 58.6	$ 15.0

3. PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

The following tables summarize the NU, CL&P, PSNH, and WMECO investments in utility plant:

	As of June 30, 2011	As of December 31, 2010
(Millions of Dollars)	NU	NU
Distribution - Electric	$ 6,350.2	$ 6,197.2

Distribution - Natural Gas		1,168.5		1,126.6
Transmission		3,407.1		3,378.0
Generation		720.6		697.1
Electric and Natural Gas Utility		11,646.4		11,398.9
Other [1]		304.4		305.5
Total Property, Plant and Equipment, Gross		11,950.8		11,704.4
Less: Accumulated Depreciation				
Electric and Natural Gas Utility		(2,938.0)		(2,862.3)
Other		(119.3)		(119.9)
Total Accumulated Depreciation		(3,057.3)		(2,982.2)
Property, Plant and Equipment, Net		8,893.5		8,722.2
Construction Work in Progress		970.3		845.5
Total Property, Plant and Equipment, Net	$	9,863.8	$	9,567.7

(1)

These assets are primarily owned by RRR ($162.8 million and $166 million) and NUSCO ($129.7 million and $126.6 million) as of June 30, 2011 and December 31, 2010, respectively, and are mainly comprised of building improvements at RRR and software and equipment at NUSCO.

	As of June 30, 2011			As of December 31, 2010		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Distribution	$ 4,293.6	$ 1,405.6	$ 684.8	$ 4,180.7	$ 1,375.4	$ 673.7
Transmission	2,649.2	497.0	260.9	2,668.4	476.1	233.5
Generation	-	711.1	9.5	-	687.7	9.4
Total Property, Plant and Equipment, Gross	6,942.8	2,613.7	955.2	6,849.1	2,539.2	916.6
Less: Accumulated Depreciation	(1,543.6)	(862.8)	(234.6)	(1,508.7)	(837.3)	(228.5)
Property, Plant and Equipment, Net	5,399.2	1,750.9	720.6	5,340.4	1,701.9	688.1
Construction Work in Progress	256.0	385.0	188.1	246.1	351.4	129.0
Total Property, Plant and Equipment, Net	$ 5,655.2	$ 2,135.9	$ 908.7	$ 5,586.5	$ 2,053.3	$ 817.1

On May 31, 2011, CL&P completed the sale of a segment of high voltage transmission lines in the town of Wallingford, Connecticut. The net book value of the assets sold was $42.5 million. CL&P will operate and maintain the lines under an operations and maintenance agreement.

4.

DERIVATIVE INSTRUMENTS

The costs and benefits of derivative contracts that meet the definition of and are designated as "normal purchases or normal sales" (normal) are recognized in Operating Expenses or Operating Revenues on the accompanying unaudited condensed consolidated statements of income, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not recorded as normal under the applicable accounting guidance are recorded at fair value as current or long-term derivative assets or liabilities. For the Regulated companies, regulatory assets or liabilities are recorded for the changes in fair values of derivatives, as these contracts are part of current regulated operating costs, or have an allowed recovery mechanism, and management believes that these costs will continue to be recovered from or refunded to customers in cost-of-service, regulated rates. Changes in fair values of NU's remaining unregulated wholesale marketing contracts are included in Net Income.

The Regulated companies are exposed to the volatility of the prices of energy and energy-related products in procuring energy supply for their customers. The costs associated with supplying energy to customers are recoverable through customer rates. The Company manages the risks associated with the price volatility of energy and energy-related products through the use of derivative contracts, many of which are accounted for as normal (for WMECO all energy derivative contracts are accounted for as normal) and the use of nonderivative contracts.

CL&P mitigates the risks associated with the price volatility of energy and energy-related products through the use of SS or LRS contracts, which fix the price of electricity purchased for customers for periods of time ranging from three months to three years and are accounted for as normal. CL&P has entered into derivatives, including FTR contracts, to manage the risk of congestion costs associated with its SS and LRS contracts. As required by regulation, CL&P has also entered into derivative and nonderivative contracts for the purchase of energy and energy-related products and contracts related to capacity. While the risks managed by these contracts are regional congestion costs and capacity price risks that are not specific to CL&P, Connecticut's electric distribution companies, including CL&P, are required to enter into these contracts. The costs or benefits from these contracts are recoverable from or refundable to CL&P's customers, and, therefore changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying unaudited condensed consolidated balance sheets.

WMECO mitigates the risks associated with the volatility of the prices of energy and energy-related products in procuring energy supply for its customers through the use of basic service contracts, which fix the price of electricity purchased for customers for periods of time ranging from three months to one year and are accounted for as normal.

PSNH mitigates the risks associated with the volatility of energy prices in procuring energy supply for its customers through its generation facilities and the use of derivative contracts, including energy forward contracts and FTRs. PSNH enters into these contracts in order to stabilize electricity prices for customers by mitigating uncertainties associated with the New England spot market. The costs or benefits from these contracts are recoverable from or refundable to PSNH's customers, and, therefore changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying unaudited condensed consolidated balance sheets.

NU, through Yankee Gas, mitigates the risks associated with supply availability and volatility of natural gas prices through the use of storage facilities and agreements to purchase natural gas supply for customers. The costs associated with mitigating these risks are recoverable from customers, and, therefore changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying unaudited condensed consolidated balance sheets.

NU, through Select Energy, has one remaining fixed price forward sales contract to serve electrical load that is part of its remaining unregulated wholesale energy marketing portfolio. NU mitigates the price risk associated with this contract through the use of forward purchase contracts. The contracts are accounted for at fair value, and changes in their fair values are recorded in Fuel, Purchased and Net Interchange Power on the accompanying unaudited condensed consolidated statements of income.

NU is also exposed to interest rate risk associated with its long-term debt. From time to time, various subsidiaries of the Company enter into forward starting interest rate swaps, accounted for as cash flow hedges, to mitigate the risk of changes in interest rates when they expect to issue long-term debt. NU parent has also entered into an interest rate swap on fixed rate long-term debt in order to balance its fixed and floating rate debt. This interest rate swap is accounted for as a fair value hedge.

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with current and long-term portions, in the accompanying unaudited condensed consolidated balance sheets. Cash collateral posted or collected under master netting agreements is recorded as an offset to the derivative asset or liability. The following tables present the gross fair values of contracts and the net amounts recorded as current or long-term derivative assets or liabilities, by primary underlying risk exposures or purpose:

	As of June 30, 2011				
	Derivatives Not Designated as Hedges				
(Millions of Dollars)	**Commodity and Capacity Contracts Required by Regulation**	**Commodity Supply and Price Risk Management**	**Hedging Instruments**	**Collateral and Netting** (1)	**Net Amount Recorded as Derivative Asset/(Liability)**
Current Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 7.7	$ -	$ 7.7
Level 3:					
CL&P	15.2	1.0	-	(11.1)	5.1
Other	-	2.2	-	-	2.2
Total Current Derivative Assets	$ 15.2	$ 3.2	$ 7.7	$ (11.1)	$ 15.0
Long-Term Derivative Assets:					
Level 3:					
CL&P	$ 160.6	$ -	$ -	$ (77.7)	$ 82.9
Other	-	3.8	-	-	3.8
Total Long-Term Derivative Assets	$ 160.6	$ 3.8	$ -	$ (77.7)	$ 86.7
Current Derivative Liabilities:					
Level 2:					
PSNH	$ -	$ (6.7)	$ (2.4)	$ -	$ (9.1)
WMECO	-	-	(1.5)	-	(1.5)
Level 3:					
CL&P	(83.3)	(0.1)	-	-	(83.4)
Other	-	(12.5)	-	0.9	(11.6)
Total Current Derivative Liabilities	$ (83.3)	$ (19.3)	$ (3.9)	$ 0.9	$ (105.6)
Long-Term Derivative Liabilities:					
Level 3:					
CL&P	$ (863.3)	$ -	$ -	$ -	$ (863.3)
Other	-	(21.4)	-	0.4	(21.0)
Total Long-Term Derivative Liabilities	$ (863.3)	$ (21.4)	$ -	$ 0.4	$ (884.3)

	As of December 31, 2010				
	Derivatives Not Designated as Hedges				
(Millions of Dollars)	Commodity and Capacity Contracts Required by Regulation	Commodity Supply and Price Risk Management	Hedging Instruments	Collateral and Netting (1)	Net Amount Recorded as Derivative Asset/(Liability)
Current Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 7.7	$ -	$ 7.7
Level 3:					
CL&P	5.8	2.1	-	-	7.9
Other	-	1.7	-	-	1.7
Total Current Derivative Assets	$ 5.8	$ 3.8	$ 7.7	$ -	$ 17.3
Long-Term Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 4.1	$ -	$ 4.1
Level 3:					
CL&P	195.9	-	-	(80.0)	115.9
Other	-	3.2	-	-	3.2
Total Long-Term Derivative Assets	$ 195.9	$ 3.2	$ 4.1	$ (80.0)	$ 123.2
Current Derivative Liabilities:					
Level 2:					
PSNH	$ -	$ (12.8)	$ -	$ -	$ (12.8)
Level 3:					
CL&P	(54.3)	(0.2)	-	7.7	(46.8)
Other	-	(12.4)	-	0.5	(11.9)
Total Current Derivative Liabilities	$ (54.3)	$ (25.4)	$ -	$ 8.2	$ (71.5)
Long-Term Derivative Liabilities:					
Level 3:					
CL&P	$ (883.1)	$ -	$ -	$ -	$ (883.1)
Other	-	(26.8)	-	0.2	(26.6)
Total Long-Term Derivative Liabilities	$ (883.1)	$ (26.8)	$ -	$ 0.2	$ (909.7)

(1)

Amounts represent cash collateral posted under master netting agreements and the netting of derivative assets and liabilities. See "Credit Risk" below for discussion of cash collateral posted under master netting agreements.

For further information on the fair value of derivative contracts, see Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," to the unaudited condensed consolidated financial statements.

Derivatives not designated as hedges

CL&P commodity and capacity contracts required by regulation: CL&P has capacity related contracts with generation facilities. These contracts and similar UI contracts, have an expected capacity of 787 MW. CL&P has a sharing agreement with UI, with 80 percent allocated to CL&P and 20 percent allocated to UI. The capacity contracts have terms up to 15 years and obligate the utilities to make or receive payments on a monthly basis to or from the generation facilities the difference between a set capacity price and the forward capacity market price received in the ISO-NE capacity markets. The largest of these generation facilities achieved commercial operation in July 2011. In addition, CL&P has a contract to purchase 0.1 million MWh of energy through 2020.

Commodity supply and price risk management: As of June 30, 2011 and December 31, 2010, CL&P had 1 million and 1.8 million MWh, respectively, remaining under FTRs that extend through December 2011 and require monthly payments or receipts.

PSNH has electricity procurement contracts with delivery dates through 2011 to purchase an aggregate amount of 0.2 million and 0.4 million MWh of power as of June 30, 2011 and December 31, 2010, respectively. In addition, PSNH has 0.2 million and 0.3 million MWh remaining under FTRs as of June 30, 2011 and December 31, 2010, respectively, that extend through December 2011 and require monthly payments or receipts.

As of June 30, 2011 and December 31, 2010, NU had approximately 0.1 million and 0.3 million MWh, respectively, of supply volumes remaining in its unregulated wholesale portfolio when expected sales to an agency that is comprised of municipalities are compared with contracted supply, both of which extend through 2013.

The following table presents the realized and unrealized gains/(losses) associated with derivative contracts not designated as hedges:

		Amount of Gain/(Loss) Recognized on Derivative Instrument			
	Location of Gain or Loss Recognized on Derivative	**For the Three Months Ended**		**For the Six Months Ended**	
(Millions of Dollars)		**June 30, 2011**	**June 30, 2010**	**June 30, 2011**	**June 30, 2010**
NU					
Commodity and Capacity Contracts Required by Regulation	Regulatory Assets/Liabilities	$ (13.0)	$ (23.1)	$ (43.2)	$ (91.8)
Commodity Supply and Price Risk Management	Regulatory Assets/Liabilities	(1.7)	1.3	(2.0)	(19.7)
Commodity Supply and Price Risk Management	Fuel, Purchased and Net Interchange Power	0.5	0.7	0.8	0.5
CL&P					
Commodity and Capacity Contracts Required by Regulation	Regulatory Assets/Liabilities	(13.0)	(23.1)	(43.2)	(91.8)
Commodity Supply and Price Risk Management	Regulatory Assets/Liabilities	(0.9)	(0.6)	(1.9)	(3.6)
PSNH					
Commodity Supply and Price Risk Management	Regulatory Assets/Liabilities	(0.8)	1.9	-	(15.7)

For the Regulated companies, monthly settlement amounts are recorded as receivables or payables and as Operating Revenues or Fuel, Purchased and Net Interchange Power on the accompanying unaudited condensed consolidated financial statements. Regulatory assets/liabilities are established with no impact to Net Income.

Hedging instruments

Fair Value Hedge: To manage the balance of its fixed and floating rate debt, NU parent has a fixed to floating interest rate swap on its $263 million, fixed rate senior notes maturing on April 1, 2012. This interest rate swap qualifies and was designated as a fair value hedge and requires semi-annual cash settlements. The changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in Interest Expense on the accompanying unaudited condensed consolidated statements of income. There was no ineffectiveness recorded for the three and six months ended June 30, 2011 and 2010. The cumulative changes in fair values of the swap and the Long-Term Debt are recorded as a Derivative Asset/Liability and an adjustment to Long-Term Debt. Interest receivable is recorded as a reduction of Interest Expense and is included in Prepayments and Other Current Assets.

The realized and unrealized gains/(losses) related to changes in fair value of the swap and Long-Term Debt as well as pre-tax Interest Expense, were as follows:

	For the Three Months Ended							
	June 30, 2011				June 30, 2010			
(Millions of Dollars)		Swap		Hedged Debt		Swap		Hedged Debt
Changes in Fair Value	$	0.9	$	(0.9)	$	3.5	$	(3.5)
Interest Recorded in Net Income		-		2.7		-		2.5

	For the Six Months Ended							
	June 30, 2011				June 30, 2010			
(Millions of Dollars)		Swap		Hedged Debt		Swap		Hedged Debt
Changes in Fair Value	$	1.3	$	(1.3)	$	7.4	$	(7.4)
Interest Recorded in Net Income		-		5.4		-		5.3

Cash Flow Hedges: In March 2011, PSNH and WMECO entered into cash flow hedges related to a portion of their respective planned debt issuances. PSNH entered into two forward starting swaps to fix the U.S. dollar LIBOR swap rate of 3.73 percent on $80 million of a planned $160 million long-term debt issuance and 3.60 percent on $120 million of planned refinancing of PCRBs. On May 19, 2011, PSNH settled one of the cash flow hedges and the $2.9 million pre-tax reduction in AOCI will be amortized over the life of the debt. WMECO entered into a forward starting swap to fix the U.S. dollar LIBOR swap rate of 3.75 percent associated with $50 million of a planned $100 million long-term debt issuance. Cash flow hedges are recorded at fair value, and the changes in the fair value of the effective portion of those contracts are recognized in AOCI. When a cash flow hedge is settled, the settlement amount is recorded in AOCI and is amortized into Net Income over the term of the underlying debt instrument. Cash flow hedges also impact Net Income when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is improbable of occurring or when the transaction is settled.

The pre-tax impact of cash flow hedging instruments on AOCI is as follows:

	Gains/(Losses) Recognized on Derivative Instruments				Gains/(Losses) Reclassified from AOCI into Interest Expense(1)				Gains/(Losses) Reclassified from AOCI into Interest Expense(1)			
	For the Three Months Ended		For the Six Months Ended		For the Three Months Ended				For the Six Months Ended			
	June 30, 2011		June 30, 2011		June 30, 2011		June 30, 2010		June 30, 2011		June 30, 2010	
NU	$	(8.7)	$	(6.8)	$	(0.1)	$	(0.1)	$	(0.2)	$	(0.2)
CL&P		-		-		(0.2)		(0.2)		(0.4)		(0.4)
PSNH		(6.8)		(5.3)		-		-		(0.1)		(0.1)
WMECO		(1.9)		(1.5)		-		-		0.1		0.1

(1)

Amounts that were reclassified from AOCI for the three and six months ended June 30, 2011 and 2010 relate to interest rate swap agreements that have been previously settled.

For further information, see Note 10, "Comprehensive Income," to the unaudited condensed consolidated financial statements.

Credit Risk

Certain derivative contracts that are accounted for at fair value, including PSNH's electricity procurement contracts and NU's sourcing contracts related to the remaining wholesale marketing contract, contain credit risk contingent features. These features require these companies to maintain investment grade credit ratings from the major rating agencies and to post cash or standby LOCs as collateral for contracts in a net liability position over specified credit limits. NU parent provides standby LOCs under its revolving credit agreement for NU subsidiaries to post with counterparties. The following summarizes the fair value of derivative contracts that are in a liability position and subject to credit risk contingent features, the fair value of cash collateral and standby LOCs posted with counterparties and the additional collateral in the form of LOCs that would be required to be posted by NU or PSNH if the respective unsecured debt credit ratings of NU parent or PSNH were downgraded to below investment grade as of June 30, 2011 and December 31, 2010:

	As of June 30, 2011			
(Millions of Dollars)	**Fair Value Subject to Credit Risk Contingent Features**	**Cash Collateral Posted**	**Standby LOCs Posted**	**Additional Cash or Standby LOCs Required if Downgraded Below Investment Grade**
NU	$ (29.7)	$ 0.9	$ 6.0	$ 25.8
PSNH	(9.1)	-	6.0	6.1
WMECO	(1.5)	-	-	1.5

	As of December 31, 2010			
(Millions of Dollars)	**Fair Value Subject to Credit Risk Contingent Features**	**Cash Collateral Posted**	**Standby LOCs Posted**	**Additional Standby LOCs Required if Downgraded Below Investment Grade**
NU	$ (30.9)	$ 0.5	$ 24.0	$ 18.5
PSNH	(12.8)	-	24.0	-

Fair Value Measurements of Derivative Instruments:

Valuation of Derivative Instruments: Derivative contracts classified as Level 2 in the fair value hierarchy include Commodity Supply and Price Risk Management contracts and Interest Rate Risk Management contracts. Commodity Supply and Price Risk Management contracts include PSNH forward contracts to purchase energy for periods for which prices are quoted in an active market. Prices are obtained from broker quotes and based on actual market activity. The contracts are valued using the mid-point of the bid-ask spread. Valuations of these contracts also incorporate discount rates using the yield curve approach. Interest Rate Risk Management contracts represent interest rate swap agreements and are valued using a market approach provided by the swap counterparty using a discounted cash flow approach utilizing forward interest rate curves.

The derivative contracts classified as Level 3 in the tables below include the Regulated companies' Commodity and Capacity Contracts Required by Regulation, and Commodity Supply and Price Risk Management contracts (CL&P and PSNH FTRs and NU's remaining wholesale marketing portfolio). For Commodity and Capacity Contracts Required by Regulation and NU's remaining unregulated wholesale marketing portfolio, fair value is modeled using income techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price. Significant observable inputs for valuations of these contracts include energy and energy-related product prices for which quoted prices in an active market exist. Significant unobservable inputs used in the valuations of these contracts include energy and energy-related product prices for future years for long-dated Commodity and Capacity Contracts Required by Regulation and future contract quantities. Discounted cash flow valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts include assumptions regarding the timing and likelihood of scheduled payments and also reflect nonperformance risk, including credit, using the default probability approach based on the counterparty's credit rating for assets and the company's credit rating for liabilities.

The remaining contracts included in Commodity Supply and Price Risk Management and classified as Level 3 in the tables below are valued using broker quotes based on prices in an inactive market.

<u>Valuations using significant unobservable inputs:</u> The following tables present changes for the three and six months ended June 30, 2011 and 2010 in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis. The Company classifies assets and liabilities in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model. In addition to these unobservable inputs, the valuation models for Level 3 assets and liabilities typically also rely on a number of inputs that are observable either directly or indirectly. Thus the gains and losses presented below include changes in fair value that are attributable to both observable and unobservable inputs. There were no transfers into or out of Level 3 assets and liabilities for the three and six months ended June 30, 2011 and 2010:

	For the Three Months Ended June 30, 2011 NU		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
<u>Derivatives, Net:</u>			
Fair Value as of Beginning of Period	$ (843.9)	$ (28.8)	$ (872.7)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income(1)	-	0.5	0.5
Regulatory Assets/Liabilities	(13.0)	(0.9)	(13.9)
Settlements	(2.7)	2.6	(0.1)
Fair Value as of End of Period	$ (859.6)	$ (26.6)	$ (886.2)
Period Change in Unrealized Gains Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ 0.2	$ 0.2

	For the Six Months Ended June 30, 2011 NU		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
<u>Derivatives, Net:</u>			
Fair Value as of Beginning of Period	$ (808.0)	$ (32.2)	$ (840.2)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income(1)	-	0.8	0.8
Regulatory Assets/Liabilities	(43.2)	(2.0)	(45.2)
Settlements	(8.4)	6.8	(1.6)
Fair Value as of End of Period	$ (859.6)	$ (26.6)	$ (886.2)
Period Change in Unrealized Gains Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ 0.6	$ 0.6

For the Three Months Ended June 30, 2011

	CL&P		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (843.9)	$ 1.3	$ (842.6)
Net Realized/Unrealized Losses Included in:			
Regulatory Assets/Liabilities	(13.0)	(0.9)	(13.9)
Settlements	(2.7)	0.5	(2.2)
Fair Value as of End of Period	$ (859.6)	$ 0.9	$ (858.7)

	For the Six Months Ended June 30, 2011 CL&P		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (808.0)	$ 1.9	$ (806.1)
Net Realized/Unrealized Losses Included in:			
Regulatory Assets/Liabilities	(43.2)	(1.9)	(45.1)
Settlements	(8.4)	0.9	(7.5)
Fair Value as of End of Period	$ (859.6)	$ 0.9	$ (858.7)

	For the Three Months Ended June 30, 2010 NU		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (792.9)	$ (41.0)	$ (833.9)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income [1]	-	0.7	0.7
Regulatory Assets/Liabilities	(23.1)	(0.6)	(23.7)
Settlements	(2.3)	2.4	0.1
Fair Value as of End of Period	$ (818.3)	$ (38.5)	$ (856.8)
Period Change in Unrealized Gains Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ 0.5	$ 0.5

	For the Six Months Ended June 30, 2010 NU		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (720.3)	$ (40.9)	$ (761.2)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income[1]	-	0.5	0.5
Regulatory Assets/Liabilities	(91.8)	(4.2)	(96.0)
Settlements	(6.2)	6.1	(0.1)
Fair Value as of End of Period	$ (818.3)	$ (38.5)	$ (856.8)
Period Change in Unrealized Losses Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ (0.1)	$ (0.1)

	For the Three Months Ended June 30, 2010 CL&P		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (792.9)	$ 2.4	$ (790.5)
Net Realized/Unrealized Losses Included in:			

Regulatory Assets/Liabilities		(23.1)		(0.6)		(23.7)
Settlements		(2.3)		-		(2.3)
Fair Value as of End of Period	$	(818.3)	$	1.8	$	(816.5)

	For the Six Months Ended June 30, 2010 CL&P					
(Millions of Dollars)		**Commodity and Capacity Contracts Required By Regulation**		**Commodity Supply and Price Risk Management**		**Total Level 3**
Derivatives, Net:						
Fair Value as of Beginning of Period	$	(720.3)	$	4.5	$	(715.8)
Net Realized/Unrealized Losses Included in:						
Regulatory Assets/Liabilities		(91.8)		(3.6)		(95.4)
Settlements		(6.2)		0.9		(5.3)
Fair Value as of End of Period	$	(818.3)	$	1.8	$	(816.5)

(1)

Realized and unrealized gains and losses on derivatives included in Net Income relate to NU's remaining wholesale marketing contracts and are reported in Fuel, Purchased and Net Interchange Power on the accompanying unaudited condensed consolidated statements of income.

5.

MARKETABLE SECURITIES (NU, WMECO)

The Company elects to record mutual funds purchased by the NU supplemental benefit trust at fair value. As such, any change in fair value of these purchased equity securities are reflected in Net Income. These equity securities, classified as Level 1 in the fair value hierarchy, totaled $44.4 million and $42.2 million as of June 30, 2011 and December 31, 2010, respectively, and are included in current Marketable Securities. Gains on these securities of $0.3 million and $2.2 million for the three and six months ended June 30, 2011 and losses of $4.2 million and $2.5 million for the three and six months ended June 30, 2010, respectively, were recorded in Other Income, Net on the accompanying unaudited condensed consolidated statements of income. Dividend income is recorded when dividends are declared and are recorded in Other Income, Net on the accompanying unaudited condensed consolidated statements of income. All other marketable securities are accounted for as available-for-sale.

Available-for-Sale Securities: The following is a summary by security type of NU's available-for-sale securities held in the NU supplemental benefit trust and WMECO's spent nuclear fuel trust. These securities are recorded at fair value and included in current and long-term Marketable Securities on the accompanying unaudited condensed consolidated balance sheets.

	As of June 30, 2011							
(Millions of Dollars)		**Amortized Cost**		**Pre-Tax Unrealized Gains(1)**		**Pre-Tax Unrealized Losses(1)**		**Fair Value**
NU								
U.S. Government Issued Debt Securities								
(Agency and Treasury)	$	13.1	$	0.3	$	-	$	13.4
Corporate Debt Securities		12.6		0.5		-		13.1
Asset Backed Debt Securities		9.4		0.4		(0.1)		9.7
Municipal Bonds		26.4		0.1		-		26.5
Money Market Funds and Other		25.5		0.2		-		25.7
Total NU	$	87.0	$	1.5	$	(0.1)	$	88.4
WMECO Spent Nuclear Fuel Trust								
Corporate Debt Securities	$	5.9	$	-	$	-	$	5.9
Asset Backed Debt Securities		3.1		-		(0.1)		3.0
Municipal Bonds		25.8		-		-		25.8
Money Market Funds and Other		22.4		-		-		22.4
Total WMECO Spent Nuclear Fuel Trust	$	57.2	$	-	$	(0.1)	$	57.1

	As of December 31, 2010							
(Millions of Dollars)		**Amortized Cost**		**Pre-Tax Unrealized Gains(1)**		**Pre-Tax Unrealized Losses(1)**		**Fair Value**

NU								
U.S. Government Issued Debt Securities (Agency and Treasury)	$	17.7	$	0.2	$	(0.1)	$	17.8
Corporate Debt Securities		22.1		0.5		(0.1)		22.5
Asset Backed Debt Securities		11.3		0.4		(0.1)		11.6
Municipal Bonds		16.1		-		-		16.1
Money Market Funds and Other		19.1		0.2		-		19.3
Total NU	$	86.3	$	1.3	$	(0.3)	$	87.3
WMECO Spent Nuclear Fuel Trust								
U.S. Government Issued Debt Securities (Agency and Treasury)	$	6.0	$	-	$	-	$	6.0
Corporate Debt Securities		15.6		-		-		15.6
Asset Backed Debt Securities		4.8		-		(0.1)		4.7
Municipal Bonds		15.4		-		-		15.4
Money Market Funds and Other		15.4		-		-		15.4
Total WMECO Spent Nuclear Fuel Trust	$	57.2	$	-	$	(0.1)	$	57.1

(1)

Unrealized gains and losses on debt securities for the NU supplemental benefit trust and WMECO spent nuclear fuel trust are recorded in AOCI and Other Long-Term Assets, respectively, on the accompanying unaudited condensed consolidated balance sheets.

Unrealized Losses and Other-than-Temporary Impairment: There have been no significant unrealized losses, other-than-temporary impairments or credit losses for the NU supplemental benefit trust or WMECO spent nuclear fuel trust. Factors considered in determining whether a credit loss exists include the duration and severity of the impairment, adverse conditions specifically affecting the issuer, and the payment history, ratings and rating changes of the security. For asset backed debt securities, underlying collateral and expected future cash flows are also evaluated.

Realized gains and losses: Realized gains and losses on available-for-sale-securities are recorded in Other Income, Net for the NU supplemental benefit trust and in Other Long-Term Assets for the WMECO spent nuclear fuel trust. NU utilizes the specific identification basis method for the NU supplemental benefit trust securities and the average cost basis method for the WMECO spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities.

Contractual Maturities: As of June 30, 2011, the contractual maturities of available-for-sale debt securities are as follows:

	NU		WMECO	
(Millions of Dollars)	**Amortized Cost**	**Fair Value**	**Amortized Cost**	**Fair Value**
Less than one year	$ 30.2	$ 30.3	$ 28.0	$ 28.0
One to five years	12.3	12.5	6.7	6.8
Six to ten years	6.3	6.7	2.0	1.9
Greater than ten years	38.2	38.9	20.5	20.4
Total Debt Securities	$ 87.0	$ 88.4	$ 57.2	$ 57.1

Fair Value Measurements: The following table presents the marketable securities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	NU		WMECO	
(Millions of Dollars)	**As of June 30, 2011**	**As of December 31, 2010**	**As of June 30, 2011**	**As of December 31, 2010**
Level 1:				
Mutual Funds	$ 44.4	$ 42.2	$ -	$ -
Money Market Funds	2.1	1.8	1.1	0.3
Total Level 1	$ 46.5	$ 44.0	$ 1.1	$ 0.3
Level 2:				
U.S. Government Issued Debt Securities (Agency and Treasury)	13.4	17.8	-	6.0
Corporate Debt Securities	13.1	22.5	5.9	15.6
Asset Backed Debt Securities	9.7	11.6	3.0	4.7
Municipal Bonds	26.5	16.1	25.8	15.4
Other Fixed Income Securities	23.6	17.5	21.3	15.1
Total Level 2	$ 86.3	$ 85.5	$ 56.0	$ 56.8
Total Marketable Securities	$ 132.8	$ 129.5	$ 57.1	$ 57.1

U.S. government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instrument and also incorporating yield curves, credit spreads and specific bond terms and conditions. Municipal bonds are valued using a market approach that incorporates reported trades and benchmark yields. Asset backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and maturity dates and tranche information. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

6.

LONG-TERM DEBT (PSNH)

On May 26, 2011, PSNH issued $122 million of Series Q first mortgage bonds with a coupon rate of 4.05 percent and a maturity date of June 1, 2021. The proceeds of these bonds were used to redeem two series of tax-exempt PCRBs. The indenture under which the bonds were issued requires PSNH to comply with certain covenants as are customarily included in such indentures.

NU, including CL&P, PSNH and WMECO, was in compliance with all its debt covenants as of June 30, 2011.

7.

PENSION BENEFITS AND POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

NUSCO sponsors a Pension Plan, which is subject to the provisions of ERISA, as amended by the PPA of 2006. The Pension Plan covers nonbargaining unit employees (and bargaining unit employees, as negotiated) of NU, including CL&P, PSNH, and WMECO, hired before 2006 (or as negotiated, for bargaining unit employees). In addition, NU maintains a SERP, which provides benefits to eligible participants who are officers of NU. This plan provides benefits that would have been provided to these employees under the Pension Plan if certain Internal Revenue Code limitations were not imposed. On behalf of NU's retirees, NUSCO also sponsors plans that provide certain retiree health care benefits, primarily medical and dental, and life insurance benefits through a PBOP Plan.

The components of net periodic benefit expense, the portion of pension amounts capitalized related to employees working on capital projects, and intercompany allocations not included in the net periodic benefit expense amounts for the Pension Plan (including the SERP) and PBOP Plan are as follows:

For the Three Months Ended June 30, 2011

	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 14.0	$ 4.9	$ 2.7	$ 1.0	$ 2.1	$ 0.7	$ 0.5	$ 0.2
Interest Cost	38.3	13.0	6.1	2.7	6.5	2.5	1.2	0.5
Expected Return on Plan Assets	(42.2)	(19.1)	(4.7)	(4.4)	(5.4)	(2.1)	(1.1)	(0.5)
Actuarial Loss	21.1	8.2	2.6	1.7	5.0	1.9	0.9	0.3
Prior Service Cost	2.4	1.0	0.5	0.2	-	-	-	-
Net Transition Obligation Cost	-	-	-	-	2.9	1.5	0.6	0.3
Total - Net Periodic Expense	$ 33.6	$ 8.0	$ 7.2	$ 1.2	$ 11.1	$ 4.5	$ 2.1	$ 0.8
Related Intercompany Allocations	N/A	$ 8.7	$ 1.9	$ 1.6	N/A	$ 2.0	$ 0.5	$ 0.9
Amount Capitalized	$ 8.0	$ 4.4	$ 2.0	$ 0.7	$ -	$ -	$ -	$ -

For the Three Months Ended June 30, 2010

	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 12.4	$ 4.3	$ 2.4	$ 0.8	$ 2.0	$ 0.7	$ 0.4	$ 0.2
Interest Cost	38.3	13.0	6.1	2.6	6.7	2.6	1.3	0.6
Expected Return on Plan Assets	(45.7)	(21.4)	(3.6)	(4.8)	(5.5)	(2.2)	(1.1)	(0.5)
Actuarial Loss	13.8	5.4	1.8	1.1	4.4	1.6	0.7	0.2
Prior Service Cost	2.5	1.0	0.4	0.3	-	-	-	-
Net Transition Obligation Cost	-	-	-	-	2.9	1.5	0.7	0.3
Total - Net Periodic Expense	$ 21.3	$ 2.3	$ 7.1	$ -	$ 10.5	$ 4.2	$ 2.0	$ 0.8
Related Intercompany Allocations	N/A	$ 6.5	$ 1.5	$ 1.2	N/A	$ 2.1	$ 0.5	$ 0.4
Amount Capitalized	$ 4.4	$ 1.8	$ 2.1	$ 0.1	$ -	$ -	$ -	$ -

For the Six Months Ended June 30, 2011

	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 27.7	$ 9.7	$ 5.3	$ 2.0	$ 4.5	$ 1.4	$ 1.0	$ 0.3
Interest Cost	76.5	26.1	12.3	5.4	12.9	5.0	2.4	1.1
Expected Return on Plan Assets	(85.3)	(38.3)	(10.0)	(8.8)	(10.8)	(4.3)	(2.2)	(1.0)
Actuarial Loss	42.1	16.6	5.2	3.4	9.5	3.6	1.6	0.6
	4.8	2.0	1.0	0.4	(0.1)	-	-	-

Prior Service Cost/(Credit)								
Net Transition Obligation Cost	-	-	-	-	5.8	3.1	1.2	0.6
Total - Net Periodic Expense	$ 65.8	$ 16.1	$ 13.8	$ 2.4	$ 21.8	$ 8.8	$ 4.0	$ 1.6
Related Intercompany Allocations	N/A	$ 16.5	$ 3.8	$ 3.0	N/A	$ 4.1	$ 1.0	$ 1.7
Amount Capitalized	$ 15.7	$ 8.9	$ 3.9	$ 1.4	$ -	$ -	$ -	$ -

	For the Six Months Ended June 30, 2010							
	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 25.5	$ 8.8	$ 4.9	$ 1.7	$ 4.3	$ 1.3	$ 0.9	$ 0.3
Interest Cost	76.3	26.0	12.1	5.3	13.4	5.2	2.5	1.1
Expected Return on Plan Assets	(91.3)	(42.9)	(7.2)	(9.7)	(10.8)	(4.3)	(2.1)	(1.0)
Actuarial Loss	26.8	10.6	3.6	2.2	8.3	3.2	1.4	0.5
Prior Service Cost/(Credit)	4.9	2.0	0.7	0.4	(0.1)	-	-	-
Net Transition Obligation Cost	-	-	-	-	5.7	3.1	1.2	0.6
Total - Net Periodic Expense/(Income)	$ 42.2	$ 4.5	$ 14.1	$ (0.1)	$ 20.8	$ 8.5	$ 3.9	$ 1.5
Related Intercompany Allocations	N/A	$ 12.6	$ 3.0	$ 2.3	N/A	$ 4.0	$ 1.0	$ 0.7
Amount Capitalized	$ 8.8	$ 3.5	$ 4.1	$ 0.3	$ -	$ -	$ -	$ -

Contributions: Currently NU s policy is to annually fund the Pension Plan in an amount at least equal to an amount that will satisfy the requirements of ERISA, as amended by the PPA of 2006, and the Internal Revenue Code. Due to an underfunded balance as of January 1, 2010, NU is required to make an additional contribution to the Pension Plan of approximately $145 million in 2011, approximately $19 million of which was made in the second quarter of 2011 ($15 million of which was contributed by PSNH). The required contribution is being made in installments, which began in April 2011, to meet the current minimum funding requirements established by the PPA of 2006. Additional contributions totalling $390 million are expected to be made from 2012 through 2015, subject to a variety of factors, including the performance of existing plan assets, valuation of the plan's liabilities and changes in long-term discount rates.

8.

COMMITMENTS AND CONTINGENCIES

A.

Environmental Matters

General: NU, CL&P, PSNH, and WMECO are subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. NU, CL&P, PSNH, and WMECO have an active environmental auditing and training program and believe that they are substantially in compliance with all enacted laws and regulations.

The environmental reserve as of June 30, 2011 and December 31, 2010 related to sites in the remediation or long-term monitoring phase is as follows:

	As of June 30, 2011			As of December 31, 2010		
	Number of Sites		Reserve (in millions)	Number of Sites		Reserve (in millions)
NU	33	$	28.4	33	$	30.3
CL&P	6		0.9	6		0.8
PSNH	12		8.2	12		8.8
WMECO	8		0.2	8		0.2

The majority of the accrual for sites in remediation or long-term monitoring relate to MGP sites that were operated several decades ago and produced manufacturing gas from coal, which resulted in certain byproducts in the environment that may pose a risk to human health and the environment.

HWP: HWP, a subsidiary of NU, continues to investigate the potential need for additional remediation at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal utility, in 1902. HWP shares responsibility for site remediation with HG&E and has conducted substantial investigative and remediation activities. The cumulative expense recorded to the reserve for this site since 1994 through June 30, 2011 was $19.5 million, of which $16.9 million had been spent, leaving $2.6 million in the reserve as of June 30, 2011. For the six months ended June 30, 2011, there was no charge recorded to the reserve and for the six months ended June 30, 2010, a pre-tax charge of $1 million was recorded to reflect estimated costs associated with the site. HWP's share of the costs related to this site is not recoverable from customers.

The $2.6 million reserve balance as of June 30, 2011 represents estimated costs that HWP considers probable over the remaining life of the project, including testing and related costs in the near term and field activities to be agreed upon with the MA DEP, further studies and long-term monitoring that are expected to be required by the MA DEP, and certain soft tar remediation activities. Various factors could affect management's estimates and require an increase to the reserve, which would be reflected as a charge to Net Income. Although a material increase to the reserve is not presently anticipated, management cannot reasonably estimate potential additional investigation or remediation costs because these costs would depend on, among other things, the nature, extent and timing of additional investigation and remediation that may be required by the MA DEP.

B.

Guarantees and Indemnifications

NU parent provides credit assurances on behalf of its subsidiaries, including CL&P, PSNH and WMECO, in the form of guarantees and LOCs in the normal course of business.

NU provided guarantees and various indemnifications on behalf of external parties as a result of the sales of former subsidiaries of NU Enterprises, with maximum exposures either not specified or not material.

NU also issued a guaranty for the benefit of Hydro Renewable Energy under which, beginning at the time the Northern Pass Transmission line goes into commercial operation, NU will guarantee the financial obligations of NPT under the TSA in an amount not to exceed $18.8 million. NU's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations.

Management does not anticipate a material impact to Net Income to result from these various guarantees and indemnifications.

The following table summarizes NU's guarantees of its subsidiaries, including CL&P, PSNH, and WMECO, as of June 30, 2011:

Subsidiary	Description	Maximum Exposure (in millions)		Expiration Dates
Various	Surety Bonds and Performance Guarantees	$	17.1	2011-2012 (1)
CL&P, PSNH and Select Energy	Letters of Credit	$	20.6	October 2011 - December 2011 -

RRR and NUSCO	Lease Payments for Real Estate and Vehicles	$	21.8	2019-2024
NU Enterprises	Surety Bonds, Insurance Bonds and Performance Guarantees	$	137.4 (2)	(2)

(1)

Surety bond expiration dates reflect bond termination dates, the majority of which will be renewed or extended.

(2)

The maximum exposure includes $58.2 million related to performance guarantees on Select Energy's wholesale purchase contracts, which expire in 2013, assuming purchase contracts guaranteed have no value; however, actual exposures vary with underlying commodity prices. The maximum exposure also includes $15.7 million related to a performance guarantee of NGS obligations for which no maximum exposure is specified in the agreement. The maximum exposure was calculated as of June 30, 2011 based on limits of NGS's liability contained in the underlying service contract and assumes that NGS will perform under that contract through its expiration in 2020. Also included in the maximum exposure is $1.2 million related to insurance bonds at NGS with no expiration date that are billed annually on their anniversary date. The remaining $62.3 million of maximum exposure relates to surety bonds covering ongoing projects at Boulos, which expire upon project completion.

CL&P, PSNH and WMECO do not guarantee the performance of third parties.

Many of the underlying contracts that NU parent guarantees, as well as certain surety bonds, contain credit ratings triggers that would require NU parent to post collateral in the event that the unsecured debt credit ratings of NU are downgraded below investment grade.

9.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of CL&P's preferred stock is based upon pricing models that incorporate interest rates and other market factors, valuations or trades of similar securities and cash flow projections. The fair value of fixed-rate long-term debt securities and RRBs is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions, credit ratings of the respective companies and treasury benchmark yields. Adjustable rate securities are assumed to have a fair value equal to their carrying value. Carrying amounts and estimated fair values are as follows:

	As of June 30, 2011							
	NU		CL&P		PSNH		WMECO	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value

(Millions of Dollars)								
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 97.6	$ 116.2	$ 97.6	$ -	$ -	$ -	$ -
Long-Term Debt	4,694.8	5,066.2	2,587.7	2,835.4	839.5	884.2	401.0	417.9
Rate Reduction Bonds	147.3	155.7	-	-	112.2	118.5	35.1	37.2

	As of December 31, 2010							
	NU		**CL&P**		**PSNH**		**WMECO**	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 93.7	$ 116.2	$ 93.7	$ -	$ -	$ -	$ -
Long-Term Debt	4,692.4	5,043.8	2,587.5	2,816.7	837.3	871.4	401.0	417.0
Rate Reduction Bonds	181.6	193.3	-	-	138.2	146.9	43.3	46.4

Derivative Instruments: NU, including CL&P and PSNH, holds various derivative instruments that are carried at fair value. For further information, see Note 4, "Derivative Instruments," to the unaudited condensed consolidated financial statements.

Other Financial Instruments: Investments in marketable securities are carried at fair value on the accompanying unaudited condensed consolidated balance sheets. For further information, see Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 5, "Marketable Securities," to the unaudited condensed consolidated financial statements.

The carrying value of other financial instruments included in current assets and current liabilities, including cash and cash equivalents and special deposits, approximates their fair value due to the short-term nature of these instruments.

10. COMPREHENSIVE INCOME

Total comprehensive income is as follows:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
(Millions of Dollars)	NU	NU	NU	NU
Net Income	$ 78.7	$ 73.3	$ 194.3	$ 160.9
Other Comprehensive Income, Net of Tax:				
Qualified Cash Flow Hedging Instruments	(5.1)	-	(3.9)	0.1
Changes in Unrealized Gains on Other Securities[1]	0.1	0.3	0.1	0.6
Change in Funded Status of Pension, SERP and PBOP Benefit Plans	0.4	0.6	1.4	1.0
Other Comprehensive Income, Net of Tax	(4.6)	0.9	(2.4)	1.7
Total Comprehensive Income	74.1	74.2	191.9	162.6
Comprehensive Income Attributable to Noncontrolling Interests	(1.4)	(1.4)	(2.9)	(2.8)
Comprehensive Income Attributable to Controlling Interests	$ 72.7	$ 72.8	$ 189.0	$ 159.8

	For the Three Months Ended June 30, 2011			For the Three Months Ended June 30, 2010		
(Millions of Dollars)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Net Income	$ 52.6	$ 21.7	$ 8.2	$ 44.1	$ 21.6	$ 5.2
Other Comprehensive Income, Net of Tax:						
Qualified Cash Flow Hedging Instruments	0.1	(4.0)	(1.1)	0.1	-	-
Other Comprehensive Income, Net of Tax	0.1	(4.0)	(1.1)	0.1	-	-
Total Comprehensive Income	$ 52.7	$ 17.7	$ 7.1	$ 44.2	$ 21.6	$ 5.2

	For the Six Months Ended June 30, 2011			For the Six Months Ended June 30, 2010		
(Millions of Dollars)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Net Income	$ 117.0	$ 49.1	$ 18.1	$ 92.5	$ 37.4	$ 10.9
Other Comprehensive Income, Net of Tax:						
Qualified Cash Flow Hedging Instruments	0.2	(3.1)	(0.9)	0.2	0.1	-
Other Comprehensive Income, Net of Tax	0.2	(3.1)	(0.9)	0.2	0.1	-
Total Comprehensive Income	$ 117.2	$ 46.0	$ 17.2	$ 92.7	$ 37.5	$ 10.9

[1] Represents changes in unrealized gains on securities held in the NU supplemental benefit trust.

Qualified cash flow hedging instruments for the six months ended June 30, 2011 are as follows:

	For the Six Months Ended June 30, 2011		
(Millions of Dollars)	**NU**	**PSNH**	**WMECO**
Balance as of Beginning of Period	$ (4.2)	$ (0.6)	$ (0.1)
Hedged Transactions Recognized into Earnings	0.1	-	-
Change in Fair Value of Interest Rate Swap Agreements	(5.1)	(4.0)	(1.1)
Cash Flow Transactions Entered into for the Period	1.1	0.9	0.2
Net Change Associated with Hedging Transactions	(3.9)	(3.1)	(0.9)
Total Fair Value Adjustments Included in Accumulated Other Comprehensive Income	$ (8.1)	$ (3.7)	$ (1.0)

For further information regarding cash flow hedging transactions, see Note 4, "Derivative Instruments," to the unaudited condensed consolidated financial statements.

11.

COMMON SHARES

The following table sets forth the NU common shares and the shares of CL&P, PSNH and WMECO common stock authorized and issued as of June 30, 2011 and December 31, 2010 and the respective par values:

		Shares		
		Authorized	**Issued**	
	Per Share Par Value	**As of June 30, 2011 and December 31, 2010**	**As of June 30, 2011**	**As of December 31, 2010**
NU	$ 5	225,000,000	195,976,708	195,781,740
CL&P	$ 10	24,500,000	6,035,205	6,035,205
PSNH	$ 1	100,000,000	301	301
WMECO	$ 25	1,072,471	434,653	434,653

As of June 30, 2011 and December 31, 2010, 19,151,327 and 19,333,659 NU common shares were held as treasury shares, respectively.

12. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS (NU)

A summary of the changes in Common Shareholders' Equity and Noncontrolling Interests of NU is as follows:

	For the Three Months Ended							
	June 30, 2011				June 30, 2010			
(Millions of Dollars)	Common Shareholders' Equity	Noncontrolling Interest	Total Equity	Preferred Stock Not Subject to Mandatory Redemption	Common Shareholders' Equity	Noncontrolling Interest	Total Equity	Preferred Stock Not Subject to Mandatory Redemption
Balance, Beginning of Period	$ 3,885.3	$ 1.5	$ 3,886.8	$ 116.2	$ 3,625.2	$ -	$ 3,625.2	$ 116.2
Net Income	78.7	-	78.7	-	73.3	-	73.3	-
Dividends on Common Shares	(48.9)	-	(48.9)	-	(45.4)	-	(45.4)	-
Dividends on Preferred Stock	(1.4)	-	(1.4)	(1.4)	(1.4)	-	(1.4)	(1.4)
Issuance of Common Shares	-	-	-	-	0.2	-	0.2	-
Contributions to NPT	-	0.3	0.3	-	-	1.1	1.1	-
Other Transactions, Net	6.0	-	6.0	-	6.1	-	6.1	-
Net Income Attributable to Noncontrolling Interests	-	-	-	1.4	-	-	-	1.4
Other Comprehensive Income (Note 10)	(4.6)	-	(4.6)	-	0.9	-	0.9	-
Balance, End of Period	$ 3,915.1	$ 1.8	$ 3,916.9	$ 116.2	$ 3,658.9	$ 1.1	$ 3,660.0	$ 116.2

	For the Six Months Ended							
	June 30, 2011				June 30, 2010			
	Common			Preferred Stock Not Subject to	Common			Preferred Stock Not Subject to

(Millions of Dollars)	**Shareholders' Equity**	**Noncontrolling Interest**	**Total Equity**	**Mandatory Redemption**	**Shareholders' Equity**	**Noncontrolling Interest**	**Total Equity**	**Mandatory Redemption**
Balance, Beginning of Period	$ 3,811.2	$ 1.5	$ 3,812.7	$ 116.2	$ 3,577.9	$ -	$ 3,577.9	$ 116.2
Net Income	194.3	-	194.3	-	160.9	-	160.9	-
Dividends on Common Shares	(97.7)	-	(97.7)	-	(90.9)	-	(90.9)	-
Dividends on Preferred Stock	(2.8)	-	(2.8)	(2.8)	(2.8)	-	(2.8)	(2.8)
Issuance of Common Shares	4.2	-	4.2	-	5.4	-	5.4	-
Contributions to NPT	-	0.3	0.3	-	-	1.1	1.1	-
Other Transactions, Net	8.3	-	8.3	-	6.7	-	6.7	-
Net Income Attributable to Noncontrolling Interests	-	-	-	2.8	-	-	-	2.8
Other Comprehensive Income (Note 10)	(2.4)	-	(2.4)	-	1.7	-	1.7	-
Balance, End of Period	$ 3,915.1	$ 1.8	$ 3,916.9	$ 116.2	$ 3,658.9	$ 1.1	$ 3,660.0	$ 116.2

For the three and six months ended June 30, 2011 and 2010, there was no change in NU parent's 100 percent ownership of the common equity of CL&P.

13.

EARNINGS PER SHARE (NU)

EPS is computed based upon the monthly weighted average number of common shares outstanding, excluding unallocated ESOP shares, during each period. Diluted EPS is computed on the basis of the monthly weighted average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common shares. The computation of diluted EPS excludes the effect of the potential exercise of share awards when the average market price of the common shares is lower than the exercise price of the related awards during the period. These outstanding share awards are not included in the computation of diluted EPS because the effect would have been antidilutive. For the six months ended June 30, 2010, there were 3,156 share awards excluded from the computation, as these awards were antidilutive. There were no antidilutive share awards outstanding for the six months ended June 30, 2011 or for the three months ended June 30, 2011 and 2010.

The following table sets forth the components of basic and diluted EPS:

(Millions of Dollars, except share information)	For the Three Months Ended June 30, 2011	For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
Net Income Attributable to Controlling Interests	$ 77.3	$ 71.9	$ 191.4	$ 158.2
Weighted Average Common Shares Outstanding:				
Basic	177,347,374	176,571,189	177,267,791	176,460,476
Dilutive Effect	279,618	165,343	286,204	176,527
Diluted	177,626,992	176,736,532	177,553,995	176,637,003
Basic and Diluted EPS	$ 0.44	$ 0.41	$ 1.08	$ 0.90

RSUs and performance shares are included in basic common shares outstanding as of the date that all necessary vesting conditions have been satisfied. The dilutive effect of outstanding RSUs and performance shares for which common shares have not been issued is calculated using the treasury stock method. Assumed proceeds of the units under the treasury stock method consist of the remaining compensation cost to be recognized and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the units (the difference between the market value of the average units outstanding for the period, using the average market price during the period, and the grant date market value).

The dilutive effect of stock options to purchase common shares is also calculated using the treasury stock method. Assumed proceeds for stock options consist of remaining compensation cost to be recognized, cash proceeds that would be received upon exercise, and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the stock options (the difference between the market value of the average stock options outstanding for the period, using the average market price during the period, and the exercise price).

Allocated ESOP shares are included in basic common shares outstanding in the above table.

14.

SEGMENT INFORMATION

Presentation: NU is organized between the Regulated companies' segments and Other based on a combination of factors, including the characteristics of each business' products and services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. Cash flows for total investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income.

The Regulated companies' segments include the electric distribution segment, the natural gas distribution segment and the electric transmission segment. The electric distribution segment includes the generation activities of PSNH and WMECO. The Regulated companies' segments represented substantially all of NU's total consolidated revenues for the three and six month periods ended June 30, 2011 and 2010.

Other in the tables below primarily consists of 1) the results of NU parent, which includes other income related to the equity in earnings of NU parent's subsidiaries and interest income from the NU Money Pool, which are both eliminated in consolidation, and interest income and expense related to the cash and debt of NU parent, respectively, 2) the revenues and expenses of NU's service companies, most of which are eliminated in consolidation, and 3) the results of other subsidiaries, which are comprised of NU Enterprises (NU's competitive businesses which primarily consist of Select Energy's remaining wholesale marketing contracts, an electrical contracting business and other operating and maintenance services contracts), RRR (a real estate subsidiary), the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company and Yankee Energy Financial Services Company) and the remaining operations of HWP that were not exited as part of the sale of the competitive generation business in 2006 and the sale of its transmission business to WMECO in December 2008.

Regulated companies' revenues from the sale of electricity and natural gas primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer.

NU's segment information for the three and six months ended June 30, 2011 and 2010, with the distribution segment segregated between electric and natural gas, is as follows (some amounts may not agree between the financial statements and the segment schedules due to rounding):

	For the Three Months Ended June 30, 2011					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 794.4	$ 78.4	$ 152.1	$ 130.8	$ (108.2)	$ 1,047.5
Depreciation and Amortization	(76.8)	(6.3)	(21.4)	(3.9)	0.4	(108.0)
Other Operating Expenses	(632.9)	(65.7)	(44.2)	(126.8)	108.2	(761.4)
Operating Income	84.7	6.4	86.5	0.1	0.4	178.1
Interest Expense	(31.0)	(5.2)	(19.1)	(8.5)	1.6	(62.2)
Interest Income	0.6	-	0.1	1.5	(1.5)	0.7
Other Income, Net	2.8	0.4	3.3	85.4	(85.3)	6.6
Income Tax (Expense)/Benefit	(17.2)	(0.4)	(28.0)	2.0	(0.9)	(44.5)
Net Income	39.9	1.2	42.8	80.5	(85.7)	78.7
Net Income Attributable to Noncontrolling Interests	(0.8)	-	(0.6)	-	-	(1.4)
Net Income Attributable to Controlling Interests	$ 39.1	$ 1.2	$ 42.2	$ 80.5	$ (85.7)	$ 77.3

	For the Six Months Ended June 30, 2011					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 1,686.0	$ 258.6	$ 310.3	$ 261.2	$ (233.4)	$ 2,282.7
Depreciation and Amortization	(168.7)	(13.1)	(44.8)	(8.3)	1.3	(233.6)
Other Operating Expenses	(1,325.1)	(199.2)	(92.5)	(261.7)	234.9	(1,643.6)
Operating Income/(Loss)	192.2	46.3	173.0	(8.8)	2.8	405.5
Interest Expense	(60.6)	(10.4)	(35.4)	(17.1)	2.7	(120.8)
Interest Income	1.9	-	0.3	2.7	(2.8)	2.1
Other Income, Net	6.6	0.8	8.1	234.9	(234.8)	15.6
Income Tax (Expense)/Benefit	(43.6)	(13.0)	(57.9)	7.8	(1.4)	(108.1)
Net Income	96.5	23.7	88.1	219.5	(233.5)	194.3
Net Income Attributable to Noncontrolling Interests	(1.7)	-	(1.2)	-	-	(2.9)
Net Income Attributable to Controlling Interests	$ 94.8	$ 23.7	$ 86.9	$ 219.5	$ (233.5)	$ 191.4
Total Assets (as of)	$ 8,836.0	$ 1,445.1	$ 3,551.4	$ 6,208.6	$ (5,598.8)	$ 14,442.3
Cash Flows for Total Investments in Plant	$ 251.1	$ 45.4	$ 146.0	$ 26.0	$ -	$ 468.5

	For the Three Months Ended June 30, 2010					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 884.5	$ 73.5	$ 154.2	$ 133.8	$ (134.6)	$ 1,111.4
Depreciation and Amortization	(111.6)	(7.0)	(21.6)	(3.5)	0.7	(143.0)
Other Operating Expenses	(696.3)	(62.0)	(45.4)	(117.1)	130.7	(790.1)
Operating Income	76.6	4.5	87.2	13.2	(3.2)	178.3
Interest Expense	(35.7)	(5.5)	(19.1)	(8.1)	1.2	(67.2)
Interest Income/(Loss)	(1.5)	-	1.2	1.4	(2.3)	(1.2)
Other Income/(Loss), Net	(0.5)	0.1	1.5	72.1	(70.4)	2.8
Income Tax (Expense)/Benefit	(10.5)	0.4	(28.3)	(1.0)	-	(39.4)
Net Income/(Loss)	28.4	(0.5)	42.5	77.6	(74.7)	73.3
Net Income Attributable to Noncontrolling Interests	(0.8)	-	(0.6)	-	-	(1.4)
Net Income/(Loss) Attributable	$ 27.6	$ (0.5)	$ 41.9	$ 77.6	$ (74.7)	$ 71.9

to Controlling
Interests

	For the Six Months Ended June 30, 2010					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 1,884.5	$ 245.2	$ 307.9	$ 257.9	$ (244.7)	$ 2,450.8
Depreciation and Amortization	(214.7)	(10.6)	(41.8)	(7.3)	1.6	(272.8)
Other Operating Expenses	(1,497.8)	(191.7)	(92.4)	(232.8)	241.7	(1,773.0)
Operating Income	172.0	42.9	173.7	17.8	(1.4)	405.0
Interest Expense	(72.2)	(10.4)	(38.5)	(15.7)	2.4	(134.4)
Interest Income/(Loss)	(0.8)	-	1.4	2.7	(3.7)	(0.4)
Other Income, Net	4.2	0.1	3.9	183.8	(182.0)	10.0
Income Tax Expense	(45.6)	(13.6)	(57.2)	(2.6)	(0.2)	(119.2)
Net Income	57.6	19.0	83.3	186.0	(184.9)	161.0
Net Income Attributable to Noncontrolling Interests	(1.6)	-	(1.2)	-	-	(2.8)
Net Income Attributable to Controlling Interests	$ 56.0	$ 19.0	$ 82.1	$ 186.0	$ (184.9)	$ 158.2
Total Assets (as of)	$ 8,860.1	$ 1,370.8	$ 3,327.7	$ 6,043.9	$ (5,372.8)	$ 14,229.7
Cash Flows for Total Investments in Plant	$ 267.9	$ 28.0	$ 113.1	$ 33.4	$ -	$ 442.4

The information related to the distribution and transmission segments for CL&P, PSNH and WMECO for the three and six months
ended June 30, 2011 and 2010 is as follows:

	CL&P - For the Three Months Ended					
		June 30, 2011			June 30, 2010	
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 489.9	$ 118.1	$ 608.0	$ 584.0	$ 123.9	$ 707.9
Depreciation and Amortization	(36.1)	(16.0)	(52.1)	(90.7)	(16.8)	(107.5)
Other Operating Expenses	(408.1)	(33.0)	(441.1)	(460.0)	(34.2)	(494.2)
Operating Income	45.7	69.1	114.8	33.3	72.9	106.2
Interest Expense	(18.5)	(15.8)	(34.3)	(21.5)	(15.7)	(37.2)
Interest Income	0.6	0.1	0.7	0.5	0.9	1.4
Other Income/(Loss), Net	(0.2)	1.5	1.3	(1.2)	0.5	(0.7)
Income Tax Expense	(7.8)	(22.1)	(29.9)	(1.9)	(23.7)	(25.6)
Net Income	$ 19.8	$ 32.8	$ 52.6	$ 9.2	$ 34.9	$ 44.1

	CL&P - For the Six Months Ended					
		June 30, 2011			June 30, 2010	
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 1,039.8	$ 241.9	$ 1,281.7	$ 1,255.2	$ 247.7	$ 1,502.9
Depreciation and Amortization	(77.7)	(33.3)	(111.0)	(166.5)	(33.5)	(200.0)
Other Operating Expenses	(859.8)	(70.1)	(929.9)	(1,001.2)	(70.0)	(1,071.2)
Operating Income	102.3	138.5	240.8	87.5	144.2	231.7
Interest Expense	(35.0)	(29.1)	(64.1)	(43.9)	(31.8)	(75.7)
Interest Income	1.2	0.2	1.4	0.9	1.1	2.0
Other Income, Net	1.3	4.0	5.3	1.1	2.5	3.6
Income Tax Expense	(20.6)	(45.8)	(66.4)	(21.3)	(47.8)	(69.1)
Net Income	$ 49.2	$ 67.8	$ 117.0	$ 24.3	$ 68.2	$ 92.5
Total Assets (as of)	$ 5,601.3	$ 2,620.7	$ 8,222.0	$ 5,675.0	$ 2,552.7	$ 8,227.7
Cash Flows for Total Investments in Plant	$ 141.9	$ 60.1	$ 202.0	$ 132.4	$ 59.3	$ 191.7

	PSNH - For the Three Months Ended					
		June 30, 2011			June 30, 2010	
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 219.1	$ 21.1	$ 240.2	$ 218.2	$ 20.1	$ 238.3
Depreciation and Amortization	(30.8)	(2.8)	(33.6)	(14.0)	(2.6)	(16.6)
Other Operating Expenses	(160.8)	(7.9)	(168.7)	(170.0)	(8.3)	(178.3)

Operating Income		27.5		10.4		37.9		34.2		9.2		43.4
Interest Expense		(8.5)		(1.9)		(10.4)		(9.9)		(2.1)		(12.0)
Interest Income/(Loss)		-		-		-		(2.2)		0.2		(2.0)
Other Income, Net		3.9		0.5		4.4		1.6		0.2		1.8
Income Tax Expense		(6.9)		(3.3)		(10.2)		(6.8)		(2.8)		(9.6)
Net Income	$	16.0	$	5.7	$	21.7	$	16.9	$	4.7	$	21.6

	PSNH - For the Six Months Ended											
	June 30, 2011						June 30, 2010					
(Millions of Dollars)	Distribution		Transmission		Total		Distribution		Transmission		Total	
Operating Revenues	$	467.0	$	42.7	$	509.7	$	457.1	$	39.8	$	496.9
Depreciation and Amortization		(74.6)		(5.6)		(80.2)		(34.0)		(5.3)		(39.3)
Other Operating Expenses		(328.7)		(15.9)		(344.6)		(358.5)		(15.8)		(374.3)
Operating Income		63.7		21.2		84.9		64.6		18.7		83.3
Interest Expense		(17.1)		(3.8)		(20.9)		(20.2)		(4.2)		(24.4)
Interest Income/(Loss)		0.4		0.1		0.5		(1.9)		0.1		(1.8)
Other Income, Net		7.3		1.0		8.3		3.5		0.5		4.0
Income Tax Expense		(16.8)		(6.9)		(23.7)		(17.9)		(5.8)		(23.7)
Net Income	$	37.5	$	11.6	$	49.1	$	28.1	$	9.3	$	37.4
Total Assets (as of)	$	2,377.2	$	507.3	$	2,884.5	$	2,316.2	$	475.6	$	2,791.8
Cash Flows for Total Investments in Plant	$	89.7	$	21.8	$	111.5	$	122.8	$	18.9	$	141.7

	WMECO - For the Three Months Ended											
	June 30, 2011						June 30, 2010					
(Millions of Dollars)	Distribution		Transmission		Total		Distribution		Transmission		Total	
Operating Revenues	$	85.4	$	13.0	$	98.4	$	82.3	$	10.2	$	92.5
Depreciation and Amortization		(9.9)		(2.6)		(12.5)		(6.9)		(2.1)		(9.0)
Other Operating Expenses		(64.1)		(3.3)		(67.4)		(66.3)		(2.9)		(69.2)
Operating Income		11.4		7.1		18.5		9.1		5.2		14.3
Interest Expense		(4.1)		(1.4)		(5.5)		(4.4)		(1.3)		(5.7)
Interest Income		0.1		-		0.1		0.1		0.1		0.2
Other Income/(Loss), Net		(0.9)		1.1		0.2		(0.8)		0.7		(0.1)
Income Tax Expense		(2.5)		(2.6)		(5.1)		(1.7)		(1.8)		(3.5)
Net Income	$	4.0	$	4.2	$	8.2	$	2.3	$	2.9	$	5.2

	WMECO - For the Six Months Ended					
	June 30, 2011			June 30, 2010		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 179.3	$ 25.8	$ 205.1	$ 172.3	$ 20.4	$ 192.7
Depreciation and Amortization	(16.5)	(5.9)	(22.4)	(14.3)	(3.0)	(17.3)
Other Operating Expenses	(136.7)	(6.5)	(143.2)	(138.1)	(6.6)	(144.7)
Operating Income	26.1	13.4	39.5	19.9	10.8	30.7
Interest Expense	(8.5)	(2.5)	(11.0)	(8.1)	(2.5)	(10.6)
Interest Income	0.1	-	0.1	0.2	0.2	0.4
Other Income/(Loss), Net	(1.9)	2.7	0.8	(0.4)	0.8	0.4
Income Tax Expense	(6.1)	(5.2)	(11.3)	(6.4)	(3.6)	(10.0)
Net Income	$ 9.7	$ 8.4	$ 18.1	$ 5.2	$ 5.7	$ 10.9
Total Assets (as of)	$ 863.6	$ 402.3	$ 1,265.9	$ 874.2	$ 290.2	$ 1,164.4
Cash Flows for Total Investments in Plant	$ 19.5	$ 57.4	$ 76.9	$ 12.8	$ 33.6	$ 46.4

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VARIABLE INTEREST ENTITIES

The Company's variable interests outside of the consolidated group are not material and consist of contracts that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. NU holds variable interests in VIEs through agreements with certain entities that own single renewable energy or peaking generation power plants and with other independent power producers. NU does not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. Therefore, NU does not consolidate any power plant VIEs.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities:

We have reviewed the accompanying condensed consolidated balance sheet of Northeast Utilities and subsidiaries (the Company) as of June 30, 2011 and the related condensed consolidated statements of income for the three-month and six-month periods ended June 30, 2011 and 2010 and of cash flows for the six-month periods ended June 30, 2011 and 2010. These interim financial statements are the responsibility of the Company s management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and consolidated statement of capitalization of the Company as of December 31, 2010, and the related consolidated statements of income, comprehensive income, common shareholders equity, and cash flows for the year ended (not present herein); and in our report dated February 25, 2011, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2010 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut

August 5, 2011

NORTHEAST UTILITIES AND SUBSIDIARIES

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

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and related combined notes included in this Quarterly Report on Form 10-Q, the First Quarter 2011 Form 10-Q, and the 2010 Form 10-K. References in this Form 10-Q to "NU," the "Company," "we," "us" and "our" refer to Northeast Utilities and its consolidated subsidiaries. All per share amounts are reported on a diluted basis.

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

The only common equity securities that are publicly traded are common shares of NU. The earnings and EPS of each business discussed below do not represent a direct legal interest in the assets and liabilities allocated to such business but rather represent a direct interest in our assets and liabilities as a whole. EPS by business is a financial measure not recognized under GAAP that is calculated by dividing the Net Income Attributable to Controlling Interests of each business by the weighted average diluted NU common shares outstanding for the period. We use this non-GAAP financial measure to evaluate earnings results and to provide details of earnings results and guidance by business. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our businesses. This non-GAAP financial measure should not be considered as an alternative to our consolidated diluted EPS determined in accordance with GAAP as an indicator of operating performance.

The discussion below also includes a non-GAAP financial measure referencing our second quarter and first half of 2011 earnings and EPS excluding expenses related to NU's proposed merger with NSTAR. We use this non-GAAP financial measure to more fully compare and explain the second quarter and first half of 2011 and 2010 results without including the impact of this non-recurring item. Due to the nature and significance of this item on Net Income, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to readers of this report in analyzing historical and future performance. This non-GAAP financial measure should not be considered as an alternative to reported Net Income Attributable to Controlling Interests 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 Interests are included under "Financial Condition and Business Analysis-Overview-Consolidated" and "Financial Condition and Business Analysis-Future

Outlook" in *Management's Discussion and Analysis*, herein. All forward-looking information for 2011 and thereafter provided in this *Management s Discussion and Analysis* assumes we will operate on a stand-alone basis, excluding the impacts of the proposed merger with NSTAR, unless otherwise indicated.

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

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

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

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changes in weather patterns,

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changes in laws, regulations or regulatory policy,

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changes in levels and timing of capital expenditures,

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

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developments in legal or public policy doctrines,

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technological developments,

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changes in accounting standards and financial reporting regulations,

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fluctuations in the value of our remaining competitive contracts,

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actions of rating agencies,

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

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other presently unknown or unforeseen factors.

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

All such factors are difficult to predict, contain uncertainties that may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see Item 1A*, Risk Factors,* included in this Quarterly Report on Form 10-Q and in our 2010 Form 10-K. This Quarterly Report on Form 10-Q and our 2010 Form 10-K also describe material contingencies and critical accounting policies and estimates in the accompanying *Management's Discussion and Analysis* and *Combined Notes to Consolidated Financial Statements*. We encourage you to review these items.

Financial Condition and Business Analysis

Proposed Merger with NSTAR:

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

Subject to the conditions in the agreement, our first quarterly dividend per common share paid after the completion of the merger will be increased to an amount that is equivalent, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing. Based on the last quarterly dividend paid by NSTAR, and assuming there are no changes to such dividend prior to the closing of the merger, this amount is expected to be approximately $0.325 per share, or approximately $1.30 per share on an annualized basis, as compared to our current annualized dividend rate of approximately $1.10 per share.

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. The companies anticipate that the regulatory approvals can be obtained to permit the merger to close in the fourth quarter of 2011. For further information regarding regulatory approvals on the proposed merger, see "Regulatory Developments and Rate Matters   NSTAR Merger Approvals," in this *Management's Discussion and Analysis.*

Executive Summary

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

Results:

The earnings discussion below is for the three and six months ended June 30, 2011, compared with the same periods in 2010:

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We earned $77.3 million, or $0.44 per share, in the second quarter of 2011, and $191.4 million, or $1.08 per share, in the first half of 2011, compared with $71.9 million, or $0.41 per share, in the second quarter of 2010 and $158.2 million, or $0.90 per share, in the first half of 2010. Excluding merger-related costs of $1.2 million, or $0.00 per share, and $9.5 million, or $0.05 per share, we earned $78.5 million, or $0.44 per share, and $200.9 million, or $1.13 per share, in the second quarter and first half of 2011, respectively. Improved results in the first half of 2011 were attributable primarily to the impact of recent electric distribution rate case decisions as well as colder than normal weather in the first quarter of 2011.

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Our Regulated companies earned $82.5 million, or $0.47 per share, in the second quarter of 2011 and $205.4 million, or $1.16 per share, in the first half of 2011, compared with earnings of $69 million, or $0.39 per share, in the second quarter of 2010, and $157.1 million, or $0.89 per share, in the first half of 2010.

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The distribution segment of our Regulated companies earned $40.3 million, or $0.23 per share, in the second quarter of 2011 and $118.5 million, or $0.67 per share, in the first half of 2011, compared with $27.1 million, or $0.15 per share, in the second quarter of 2010, and $75 million, or $0.43 per share, in the first half of 2010. The transmission segment of our Regulated companies earned $42.2 million, or $0.24 per share, in the second quarter of 2011 and $86.9 million, or $0.49 per share, in the first half of 2011, compared with $41.9 million, or $0.24 per share, in the second quarter of 2010, and $82.1 million, or $0.46 per share, in the first half of 2010.

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NU parent and other companies recorded net expenses of $5.2 million, or $0.03 per share, in the second quarter of 2011 and $14 million, or $0.08 per share, in the first half of 2011, compared with earnings of $2.9 million, or $0.02 per share, in the second quarter of 2010 and $1.1 million, or $0.01 per share, in the first half of 2010. The second quarter and first half of 2011 results include after-tax expenses of $1.2 million, or $0.00 per share, and $9.5 million, or $0.05 per share, respectively, related to NU s proposed merger with NSTAR.

Outlook:

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We now project consolidated 2011 earnings of between $2.30 per share and $2.40 per share, excluding projected after-tax merger-related costs of approximately $0.20 per share. This projection includes updated distribution segment earnings of between $1.30 per share and $1.35 per share. We continue to project transmission segment earnings of between $1.05 per share and $1.10 per share, and net expenses at NU parent and other companies of approximately $0.05 per share, excluding merger expenses. Previously, we had projected consolidated 2011 earnings of between $2.25 per share and $2.40 per share, excluding merger expenses, and distribution segment earnings of between $1.25 per share and $1.35 per share.

Strategy, Legislative, Regulatory and Other Items:

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On June 15, 2011, the DOE extended the scoping comment period on NPT's proposed Northern Pass transmission line. NPT continues to work with communities and landowners in northern New Hampshire to identify new preferred routes for the right-of-way. Assuming timely receipt of all siting permits by NPT, NU now believes that construction of the line will commence in 2014 and will be completed in the fourth quarter of 2016.

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On July 1, 2011, Connecticut Governor Dannel Malloy signed legislation that consolidates oversight of state energy and environmental activities into a new Department of Energy and Environmental Protection (DEEP). Effective July 1, 2011, the DPUC was replaced by the Public Utility Regulatory Authority (PURA), which is now part of the DEEP.

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On June 29, 2011, the DPUC (now PURA) issued a final decision in the Yankee Gas rate application filed on January 7, 2011. The DPUC authorized a rate reduction of $0.5 million effective July 20, 2011 and an incremental increase of $6.7 million effective July 1, 2012. The new rates were based in part on an authorized regulatory ROE of 8.83 percent and a capital structure of 52.2 percent common equity and 47.8 percent debt. On July 14, 2011, Yankee Gas filed a motion for reconsideration with the PURA on certain issues. On August 2, 2011, the PURA issued a draft decision, which would grant Yankee Gas' motion and reopen the case on the issue regarding Yankee Gas' proposal to reduce accumulated deferred income taxes (ADIT) by the tax effect of net operating loss.

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On June 21, 2011, Governor Malloy signed legislation approving the state budget for the 2012 fiscal year. That budget revoked authority for the state to issue economic recovery revenue bonds approved by the legislature in mid-2010 to help balance the state budget for the 2011 fiscal year, which would have been collected through a charge on customers' bills.

Liquidity:

Except as otherwise noted, cash flow data discussed below is for the first half of 2011, compared with the same period in 2010:

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Cash and cash equivalents totaled $15.1 million as of June 30, 2011, compared with $23.4 million as of December 31, 2010.

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Cash capital expenditures totaled $468.5 million in the first half of 2011, compared with $442.4 million in the first half of 2010.

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Cash flows provided by operating activities totaled $652.4 million in the first half of 2011, compared with $405.2 million in the first half of 2010 (amounts are net of RRB payments). The 2011 improved cash flows were due primarily to the impact of the recent electric distribution rate case decisions and a decrease in income tax payments largely attributable to the accelerated depreciation provisions of the 2010 Tax Act. Cash flows used in investing activities for the first half of 2011 had a $46.8 million benefit related to proceeds received from the sale of certain CL&P transmission assets.

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On May 26, 2011, PSNH issued $122 million of first mortgage bonds with a coupon rate of 4.05 percent. Proceeds were used to redeem two series of tax-exempt PCRBs, each with a coupon rate of 6 percent.

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 Interests and diluted EPS, for the second quarter and first half of 2011 and 2010 is as follows:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars, Except Per Share Amounts)	**2011**		**2010**		**2011**		**2010**	
	Amount	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income Attributable to Controlling Interests (GAAP)	$ 77.3	$ 0.44	$ 71.9	$ 0.41	$ 191.4	$ 1.08	$ 158.2	$ 0.90
Regulated Companies	$ 82.5	$ 0.47	$ 69.0	$ 0.39	$ 205.4	$ 1.16	$ 157.1	$ 0.89
NU Parent and Other Companies	(4.0)	(0.03)	2.9	0.02	(4.5)	(0.03)	1.1	0.01
Non-GAAP Earnings	78.5	0.44	71.9	0.41	200.9	1.13	158.2	0.90
Merger-Related Costs (after-tax)	(1.2)	-	-	-	(9.5)	(0.05)	-	-
Net Income Attributable to Controlling Interests (GAAP)	$ 77.3	$ 0.44	$ 71.9	$ 0.41	$ 191.4	$ 1.08	$ 158.2	$ 0.90

Improved results in the second quarter of 2011 were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010 and the WMECO distribution rate case decision that was effective February 1, 2011. These benefits were partially offset by a decline in NU parent and other companies' results in the second quarter of 2011, as compared to the same period in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year. Second quarter 2011 results reflect a refund to transmission wholesale customers, compared to a recovery from those customers in 2010.

Improved results in the first half of 2011 were due primarily to the impact of the rate case decisions, colder than normal weather in the first quarter of 2011, increased earnings in the transmission segment due to the increased investment in transmission infrastructure, continued cost management efforts, and the absence of a net after-tax charge of approximately $3 million, or approximately $0.02 per share, taken in the first quarter of 2010 associated with the enactment of the 2010 Healthcare Act. These benefits were partially offset by the decline in NU parent and other companies' results, the second quarter 2011 refund to transmission wholesale customers, compared to a recovery in 2010, as well as higher pension costs and property taxes. Retail electric sales were up 0.9 percent and firm natural gas sales were up 18.4 percent in the first half of 2011, compared to the same period in 2010.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(Millions of Dollars)	**2011**	**2010**	**2011**	**2010**
CL&P Transmission	$ 32.2	$ 34.3	$ 66.6	$ 67.1
PSNH Transmission	5.6	4.6	11.6	9.3
WMECO Transmission	4.2	3.0	8.4	5.7
NPT	0.2	-	0.3	-
Total Transmission	42.2	41.9	86.9	82.1
CL&P Distribution	19.1	8.4	47.6	22.7
PSNH Distribution	16.0	16.9	37.5	28.1
WMECO Distribution	4.0	2.3	9.7	5.2
Yankee Gas	1.2	(0.5)	23.7	19.0
Total Distribution	40.3	27.1	118.5	75.0
Net Income Regulated Companies	$ 82.5	$ 69.0	$ 205.4	$ 157.1

The higher second quarter and first half of 2011 transmission segment earnings primarily reflect increased investment in transmission infrastructure to meet the reliability needs of our customers and the region. The first half of 2011 also reflects the absence of a $0.8 million after-tax charge taken in the first quarter of 2010 associated with the 2010 Healthcare Act. These were partially offset by the refund to transmission wholesale customers in 2011, as compared to a recovery from those customers in 2010, primarily impacting CL&P. For the second quarter and first half of 2011, this after-tax net impact reduced CL&P transmission earnings by $3.7 million and $5.4 million, respectively.

CL&P s second quarter 2011 distribution segment earnings were $10.7 million higher than the second quarter of 2010 due primarily to the impact of the 2010 distribution rate case decision that was effective July 1, 2010, partially offset by a 1.6 percent decrease in retail electric sales, and higher pension and healthcare costs, as well as other operations and maintenance expenses.

For the first half of 2011, CL&P s distribution segment earnings were $24.9 million higher than the same period in 2010 due primarily to the impact of the 2010 distribution rate case decision, higher retail electric sales of 0.9 percent, lower storm restoration costs and lower uncollectibles expense, partially offset by higher pension and healthcare costs, as well as other operations and maintenance expenses. For the twelve months ended June 30, 2011, CL&P s distribution segment regulatory ROE was 9.8 percent, and for 2011, we expect it to be approximately 9 percent.

PSNH s second quarter 2011 distribution segment earnings were $0.9 million lower than the same period in 2010 due primarily to the absence of the 2010 favorable impact relating to the permanent distribution rate case settlement approved on June 28, 2010, which allowed for the recovery of certain actual expenses retroactive to August 1, 2009. In addition, operations and maintenance expenses and depreciation were higher in the second quarter of 2011 and retail electric sales were 0.4 percent lower than the same period in 2010. These unfavorable impacts were partially offset by higher revenues resulting from the distribution rate increase effective July 1, 2010, and higher AFUDC earnings related to the Clean Air Project capital expenditures.

For the first half of 2011, PSNH s distribution segment earnings were $9.4 million higher than the same period of 2010 due primarily to higher revenues resulting from the permanent distribution rate increase, and a 1.2 percent increase in retail electric sales, partially offset by the absence of the 2010 favorable impact of the permanent distribution rate case settlement described above and higher operations and maintenance costs, and depreciation. For the twelve months ended June 30, 2011, PSNH s distribution segment regulatory ROE was 10.3 percent and for 2011, we expect it to be approximately 9 percent.

WMECO s second quarter 2011 distribution segment earnings were $1.7 million higher than the same period of 2010 due primarily to the impact of the DPU distribution rate case decision effective February 1, 2011 that included an annualized rate increase of $16.8 million and sales decoupling, and lower uncollectibles expenses, partially offset by higher amortization and depreciation expense.

For the first half of 2011, WMECO s distribution segment earnings were $4.5 million higher than the same period of 2010 due primarily to higher revenues resulting from the DPU distribution rate case decision effective February 1, 2011, slightly higher retail sales in January 2011 before decoupling took effect, and lower uncollectibles expenses, partially offset by higher amortization and depreciation expense. For the twelve months ended June 30, 2011, WMECO s distribution segment regulatory ROE was 6.5 percent and for 2011, we expect it to be approximately 9 percent.

Yankee Gas second quarter 2011 earnings were $1.7 million higher than the same period of 2010 due primarily to a 22.2 percent increase in total firm natural gas sales and lower uncollectibles expense, partially offset by higher expenses including pension and other healthcare costs, operations and maintenance costs, depreciation, and property taxes.

For the first half of 2011, Yankee Gas earnings were $4.7 million higher than the same period of 2010 due primarily to higher revenues resulting from an 18.4 percent increase in total firm natural gas sales, and lower uncollectibles expense, partially offset by higher pension and other healthcare costs, depreciation, and property taxes. For the twelve months ended June 30, 2011, Yankee Gas regulatory ROE was 9.9 percent. On June 29, 2011, the DPUC (now PURA) issued a final decision on Yankee Gas request to raise its distribution rates and changed Yankee Gas authorized regulatory ROE from 10.1 percent to 8.83 percent. On July 14, 2011, Yankee Gas filed a motion for reconsideration with the PURA on certain issues. On August 2, 2011, the PURA issued a draft decision, which would grant Yankee Gas' motion and reopen the case on the issue regarding Yankee Gas' proposal to reduce ADIT by the tax effect of net operating loss.

On June 1, 2011, a series of severe thunderstorms with high winds, including a tornado, struck portions of WMECO s service territory, including the city of Springfield, Massachusetts. Approximately 17,000 WMECO customers were without power. The cost of restoring power, including rebuilding certain overhead electric distribution equipment and services, was approximately $4.1 million, of which $3.9 million has been capitalized or deferred for future recovery under WMECO s major storm recovery mechanism. On June 9, 2011, another series of severe thunderstorms with high winds struck CL&P, PSNH and WMECO's service territories, resulting in power outages for approximately 260,000 customers, 210,000 at CL&P alone. The cost of restoration is estimated to be approximately $13.3 million, of which $11.1 million was incurred at CL&P. Of that sum, CL&P capitalized approximately $0.9 million and deferred approximately $7.9 million for recovery from customers as a major storm expense. PSNH and WMECO costs totaled $2.2 million, of which $1.3 million has been either capitalized or deferred for future recovery under certain regulatory recovery mechanisms.

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

For the Three Months Ended June 30, 2011 Compared to 2010

	CL&P		**PSNH**		**WMECO**		**Total Electric**			
	Percentage Increase/ (Decrease)	**Weather Normalized Percentage Increase/ (Decrease)**	**Percentage Increase/ (Decrease)**	**Weather Normalized Percentage Increase/ (Decrease)**	**Percentage Increase/ (Decrease)**	**Weather Normalized Percentage Increase/ (Decrease)**	**Sales (GWh)**		**Percentage Increase/ (Decrease)**	**We Norn Perc Incr (Dec**
Residential	0.2%	0.4%	(0.6)%	(2.1)%	2.2%	1.8%	3,228	3,220	0.3%	
Commercial	(3.1)%	(2.1)%	0.2%	0.1%	(3.4)%	(2.5)%	3,534	3,620	(2.4)%	
Industrial	(2.8)%	(1.7)%	(1.3)%	(0.5)%	(1.5)%	(0.7)%	1,131	1,156	(2.2)%	
Other	2.0%	2.0%	(4.9)%	(4.9)%	(3.3)%	(3.3)%	73	72	1.2%	
Total	(1.6)%	(1.0)%	(0.4)%	(0.8)%	(0.9)%	(0.5)%	7,966	8,068	(1.3)%	

For the Six Months Ended June 30, 2011 Compared to 2010

	CL&P		PSNH		WMECO		Total Electric		
	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Sales (GWh)		Percentage Increase/ (Decrease)
Residential	3.5%	-	2.4%	(0.6)%	4.1%	1.0%	7,351	7,116	3.3%
Commercial	(1.3)%	(1.5)%	0.8%	0.1%	(3.0)%	(2.9)%	7,007	7,076	(1.0)%
Industrial	(0.8)%	(0.2)%	(0.5)%	(0.1)%	0.5%	1.0%	2,153	2,164	(0.5)%
Other	0.3%	0.3%	(5.3)%	(5.3)%	(0.8)%	(0.8)%	160	160	(0.1)%
Total	0.9%	(0.6)%	1.2%	(0.2)%	0.6%	(0.6)%	16,671	16,516	0.9%

For the Three Months Ended June 30, 2011 Compared to 2010
Firm Natural Gas

	Sales (million cubic feet) [1]		Percentage Increase	Weather Normalized Percentage Increase
Residential	2,014	1,659	21.4%	7.8%
Commercial	2,775	2,013	37.9%	25.7%
Industrial	3,691	3,269	12.9%	11.2%
Total	8,480	6,941	22.2%	14.7%
Total, Net of Special Contracts [2]	6,450	5,027	28.3%	17.7%

For the Six Months Ended June 30, 2011 Compared to 2010
Firm Natural Gas

	Sales (million cubic feet) [1]		Percentage Increase	Weather Normalized Percentage Increase/ (Decrease)
Residential	8,794	7,763	13.3%	(2.0)%
Commercial	10,399	8,040	29.3%	13.6%
Industrial	8,671	7,726	12.2%	8.0%
Total	27,864	23,529	18.4%	6.6%
Total, Net of Special Contracts [2]	23,390	19,274	21.4%	6.8%

(1)

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

(2)

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

For the second quarter of 2011, actual and weather normalized retail electric sales for all three electric companies were lower than the same period in 2010. Cooling degree days in Connecticut and Western Massachusetts were 35.8 percent lower than last year but 5.6 percent above normal. In New Hampshire, cooling degree days were 18.1 percent lower than last year but 11.3 percent above normal. For WMECO, the fluctuations in retail electric sales no longer impact earnings as the DPU approved a sales decoupling plan effective February 1, 2011. Under this decoupling plan, WMECO now has an established level of baseline distribution delivery service revenues of $125.6 million that it is able to recover, which effectively breaks the relationship between KWhs consumed by customers and revenues recognized.

For the first half of 2011, actual retail electric sales for all three electric companies were higher than the same period in 2010 due to significantly colder weather in the first quarter of 2011 as compared to the first quarter of 2010. In the first quarter of 2011, heating degree days in Connecticut and western Massachusetts were 18.6 percent higher than last year and in New Hampshire, heating degree days were 17.7 percent higher than last year. On a weather normalized basis, our total actual retail electric sales for the first half of 2011 are lower than they were in the same period in 2010, although the results vary by electric company and customer class. Overall, we believe our customers continue to be impacted by the effects of a weak economic recovery and increased conservation efforts. In addition, our commercial and industrial electric sales continue to be negatively impacted by distributed generation programs.

Our firm natural gas sales are subject to many of the same influences as our retail electric sales, but have benefitted from a favorable price for natural gas, migration of interruptible customers switching to firm rates, and the addition of gas-fired distributed generation in Yankee Gas' service territory. Actual firm natural gas sales in the second quarter of 2011 and for the first half of 2011 were 22.2 percent higher and 18.4 percent higher than the same periods in 2010, respectively. Colder weather, especially in the first quarter of 2011, was a contributing factor to the higher sales. On a weather normalized basis, actual firm natural gas sales in the second quarter of 2011 were 14.7 percent higher than last year and for the first half of 2011, actual firm natural gas sales were 6.6 percent higher than the same period in 2010.

Our expense related to uncollectible receivable balances (our uncollectibles expense) is influenced by the economic conditions of our region. Fluctuations in our uncollectibles expense are mitigated from an earnings perspective because a portion of the total uncollectibles expense for each of the electric distribution companies is allocated for recovery to the respective company s energy supply rate and recovered through its tariffs. Additionally, for CL&P and Yankee Gas, write-offs of uncollectible receivable balances attributable to qualified customers under financial or medical duress (hardship customers) are fully recovered through their respective tariffs. For the second quarter of 2011, our total pre-tax uncollectibles expense that impacts earnings was $3.5 million as compared to $5 million in the second quarter of 2010. For the first half of 2011, our total pre-tax uncollectibles expense that impacts earnings was $7.1 million as compared to $12.9 million for the first half of 2010. The improvement in 2011 uncollectibles expense was due in part to continued enhanced accounts receivable collection efforts and credit monitoring.

NU Parent and Other Companies: NU parent and other companies (which includes our competitive businesses held by NU Enterprises) recorded net expenses of $5.2 million, or $0.03 per share, in the second quarter of 2011 and $14 million, or $0.08 per share, in the first half of 2011, compared with earnings of $2.9 million, or $0.02 per share, in the second quarter of 2010 and $1.1 million, or $0.01 per share, in the first half of 2010. The second quarter and first half of 2011 results include after-tax expenses of $1.2 million, or $0.00 per share, and $9.5 million, or $0.05 per share, respectively, associated with the proposed merger with NSTAR. For the three and six months ended June 30, 2011, our competitive business' earnings decreased by $5.3 million and $7.2 million, respectively, when compared to the same periods in 2010, as we continue to wind down the business.

Future Outlook

EPS Guidance: Following is a summary of our previously reported and revised projected 2011 EPS by business, which also reconciles consolidated diluted EPS to the non-GAAP financial measure of EPS by business. Non-GAAP EPS by business also excludes a $0.20 per share charge related to projected non-recurring merger costs we expect to incur relating to financial advisor costs, legal, accounting and consulting fees, which will affect NU parent and other companies' results. The number of outstanding NU common shares used to calculate this guidance was approximately 177 million shares.

	Previously Reported 2011 EPS Range		**Revised 2011 EPS Range**	
(Approximate amounts)	**Low**	**High**	**Low**	**High**
Diluted EPS (GAAP)	$ 2.05	$ 2.20	$ 2.10	$ 2.20
Regulated Companies:				
Distribution Segment	$ 1.25	$ 1.35	$ 1.30	$ 1.35
Transmission Segment	1.05	1.10	1.05	1.10
Total Regulated Companies	2.30	2.45	2.35	2.45
NU Parent and Other Companies	(0.05)	(0.05)	(0.05)	(0.05)
Non-GAAP EPS	$ 2.25	$ 2.40	$ 2.30	$ 2.40
Merger-Related Costs	(0.20)	(0.20)	(0.20)	(0.20)
Diluted EPS (GAAP)	$ 2.05	$ 2.20	$ 2.10	$ 2.20

The revised 2011 EPS range includes distribution segment earnings updated for an increase of $0.05 per share to the low end of the range. This projection also reflects operations on a stand-alone basis in 2011, although our proposed merger with NSTAR is expected to close in the fourth quarter of 2011. Projected impacts of the CL&P, PSNH, WMECO and Yankee Gas distribution rate case decisions are reflected in our 2011 earnings guidance. The 2011 distribution and transmission earnings guidance reflects the impact of a higher rate base as well as $1.2 billion of projected capital expenditures in 2011.

Liquidity

Consolidated: Cash and cash equivalents totaled $15.1 million as of June 30, 2011, compared with $23.4 million as of December 31, 2010.

On May 26, 2011, PSNH issued $122 million of first mortgage bonds with a coupon rate of 4.05 percent and a maturity date of June 1, 2021, and used the proceeds to redeem approximately $120 million of tax-exempt 1992 Series D and 1993 Series E PCRBs with maturity dates of May 1, 2021 and coupon rates of 6 percent.

We expect to issue approximately $260 million of long-term debt in the second half of 2011, consisting of $160 million to be issued by PSNH and $100 million to be issued by WMECO.

Cash flows provided by operating activities in the first half of 2011 totaled $652.4 million, compared with operating cash flows of $405.2 million in the first half of 2010 (all amounts are net of RRB payments, which are included in financing activities on the accompanying unaudited condensed consolidated statements of cash flows). The improved cash flows were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010 (the CL&P July 1, 2010 rate case increase was deferred from customer bills until January 1, 2011), the WMECO distribution rate case decision that was effective February 1, 2011, a net positive cash flow impact of approximately $120 million largely attributable to accelerated depreciation tax benefits, and the absence in the first half of 2011 of payments related to 2010 major storm costs. Offsetting these benefits were a second quarter 2011 contribution into the Pension Plan of $19.2 million and payments of approximately $12 million made in the first half of 2011 for merger-related costs.

We continue to project 2011 cash flows provided by operating activities of approximately $900 million to $950 million, net of RRB payments. Those cash flows reflect approximately $145 million of contributions to the Pension Plan, of which $19.2 million was contributed in the first half of 2011.

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

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

On May 16, 2011, S&P raised all of its corporate credit ratings and debt ratings on NU and its regulated utilities by one notch due primarily to improved financial metrics at the companies. S&P maintained its Watch-Positive outlook pending consummation of NU s merger with NSTAR. On July 14, 2011, Fitch affirmed its existing ratings and outlooks of NU Parent, CL&P, PSNH and WMECO.

We paid common dividends of $97.2 million in the first half of 2011, compared with $90.2 million in the first half of 2010. The increase reflects an approximately 7.3 percent increase in our common dividend rate that took effect in the first quarter of 2011. On July 12, 2011, our Board of Trustees declared a quarterly common dividend of $0.275 per share, payable on September 30, 2011 to shareholders of record as of September 1, 2011, which equates to $1.10 per share on an annualized basis.

Assuming completion of our proposed merger with NSTAR and subject to the conditions in the merger agreement, our first quarterly dividend per common share paid after the completion of the proposed merger will be increased to an amount that is equivalent, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing. Based on the last quarterly dividend paid by NSTAR of $0.425 per share, and assuming there are no changes to such dividend prior to the closing of the merger, that would result in NU s quarterly dividend being increased by 18 percent to approximately $0.325 per share, or approximately $1.30 per share on an annualized basis.

In the first half of 2011, CL&P, PSNH, WMECO, and Yankee Gas paid $168.7 million, $29.4 million, $13.2 million, and $38.2 million, respectively, in common dividends to NU parent. In the first half of 2011, NU parent made equity contributions to PSNH, WMECO, and Yankee Gas of $20 million, $5.2 million, and $8.5 million, respectively. No equity contributions were made to CL&P in the first half of 2011.

Cash capital expenditures included on the accompanying unaudited condensed consolidated statements of cash flows and described in this "Liquidity" section do not include amounts incurred on capital projects but not yet paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. A summary of our cash capital expenditures by company for the first half of 2011 and 2010 is as follows:

	For the Six Months Ended June 30,	
(Millions of Dollars)	**2011**	**2010**
CL&P	$ 202.0	$ 191.7
PSNH	111.5	141.7
WMECO	76.9	46.4
Yankee Gas	45.4	28.0
NPT	6.8	1.3
Other	25.9	33.3
Total	$ 468.5	$ 442.4

The increase in our cash capital expenditures was the result of higher transmission segment cash capital expenditures of $32.9 million, primarily at WMECO and NPT, as well as higher capital expenditures at Yankee Gas related to the WWL Project.

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

As of June 30, 2011, NU parent had $20.6 million of LOCs issued for the benefit of certain subsidiaries ($4 million for CL&P and $12.2 million for PSNH) and $95 million of short-term borrowings outstanding under its three-year $500 million unsecured revolving credit facility. The weighted-average interest rate on these short-term borrowings as of June 30, 2011 was 2.09 percent, which is based on a variable rate plus an applicable margin based on NU parent's credit ratings. NU parent had $384.4 million of borrowing availability on this facility as of June 30, 2011.

CL&P, PSNH, WMECO, and Yankee Gas maintain a joint three-year unsecured revolving credit facility in a nominal aggregate amount of $400 million. As of June 30, 2011, PSNH and WMECO had short-term borrowings outstanding under this facility of $22 million and $20 million, respectively, leaving $358 million of aggregate borrowing capacity available. The weighted-average interest rate on these short-term borrowings as of June 30, 2011 was 4.03 percent, which is based on a variable rate plus an applicable margin based on PSNH and WMECO s respective credit ratings.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portions of pension and PBOP expense or income (all of which are non-cash factors), totaled $500.1 million in the first half of 2011, compared with $454.4 million in the first half of 2010. These amounts included $24.4 million and $29.8 million in the first half of 2011 and 2010, respectively, related to our corporate service companies, NUSCO and RRR.

Regulated Companies: Capital expenditures for the Regulated companies are expected to total approximately $1.2 billion ($474 million for CL&P, $284 million for PSNH, and $287 million for WMECO) in 2011, which includes planned spending of approximately $32 million for our corporate service companies.

Transmission Segment: Transmission segment capital expenditures increased by $50.9 million in the first half of 2011, as compared with the same period in 2010, due primarily to increases at WMECO related to GSRP. A summary of transmission segment capital expenditures by company in the first half of 2011 and 2010 is as follows:

	For the Six Months Ended June 30,			
(Millions of Dollars)		**2011**		**2010**
CL&P	$	49.6	$	51.2
PSNH		22.7		21.9
WMECO		83.8		37.4
NPT		8.0		2.7
Totals	$	164.1	$	113.2

NEEWS: Substation construction and site work for overhead line construction in upland areas continues in Massachusetts on GSRP, a project that involves the construction of 115 KV and 345 KV lines from Ludlow, Massachusetts to Bloomfield, Connecticut. GSRP is the first, largest and most complicated project within the NEEWS family of projects. CL&P and WMECO expect to receive their final outstanding permits in the third quarter of 2011, at which time full overhead line construction in Massachusetts is expected to begin. CL&P expects to begin construction on the overhead section in Connecticut in early 2012 and to place the project in service in late 2013.

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, is our second major NEEWS project. In August 2010, ISO-NE reaffirmed the need for a slightly modified Interstate Reliability Project, which is expected to be placed in service in late 2015. This in-service date assumes that all siting applications are filed in late 2011, with approvals received in late 2013 and construction commencing in late 2013 or early 2014. CL&P is in the process of, and on target with, submitting all permit and siting filings.

The Central Connecticut Reliability Project, which involves construction of a new 345 KV overhead line from Bloomfield, Connecticut to Watertown, Connecticut, is the third major part of NEEWS. In March 2011, ISO-NE announced that it would review the Central Connecticut Reliability Project along with other central Connecticut projects and expects to have preliminary need results in late 2011.

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

Since inception of NEEWS through June 30, 2011, CL&P and WMECO have capitalized approximately $110.2 million and $208.9 million, respectively, in costs associated with NEEWS, of which $11.5 million and $72 million, respectively, were capitalized in the first half of 2011.

On May 27, 2011, the FERC accepted CL&P s and WMECO s filing requesting changes to the ISO-NE Tariff in order to include 100 percent of the NEEWS CWIP in regional rate base effective June 1, 2011. As a result of this order, CL&P and WMECO ceased accruing AFUDC on NEEWS CWIP as of June 1, 2011, and NU s local customers will receive appropriate credits for the return on CWIP they have paid. Our expected costs for the NEEWS projects have been revised to reflect the removal of AFUDC costs as a result of this order. We have revised our expected cost of GSRP from $795 million to $718 million, the Interstate Reliability Project from $251 million to $218 million and the Central Connecticut Reliability Project from $338 million to $301 million. The collection of NEEWS CWIP in regional rate base and the related revision in project costs will not have a material impact on earnings. As a result, the total expected cost of NEEWS will now be approximately $1.35 billion.

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

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

the construction phases under the TSA, NPT will be recording non-cash AFUDC earnings. On April 13, 2011, the FERC issued an order in the NPT proceeding accepting various rehearing requests.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE, which seeks permission to construct and maintain facilities that cross the Québec-New Hampshire border and connect to HQ TransÉnergie's facilities in Québec. The DOE held seven meetings in New Hampshire in mid-March 2011 seeking public comment. In response to concerns raised at these meetings, NPT revised its application to request additional time during the public comment period to allow NPT to review alternative routes. On June 15, 2011, the DOE extended the scoping comment period for at least forty-five days after NPT files an alternative route with the DOE. NPT expects to submit that route later this year.

NPT is evaluating a number of different possible alternatives for the northern portion of the route. Additionally, once this route has been identified, certain environmental studies will need to be completed in order to obtain DOE permits. This extended evaluation process is expected to result in the commencement of construction in 2014 and completion in the fourth quarter of 2016. The effect on the project s budget is not expected to be material.

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

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

Distribution Segment: A summary of distribution segment capital expenditures by company for the first half of 2011 and 2010 is as follows:

	For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**		**2010**	
CL&P:				
Basic Business	$	64.5	$	54.4
Aging Infrastructure		55.5		39.5
Load Growth		29.9		41.8

Total CL&P		149.9		135.7
PSNH:				
Basic Business		16.9		18.8
Aging Infrastructure		12.4		8.3
Load Growth		11.2		11.1
Total PSNH		40.5		38.2
WMECO:				
Basic Business		8.3		7.7
Aging Infrastructure		4.9		4.5
Load Growth		3.4		1.4
Total WMECO		16.6		13.6
Totals - Electric Distribution (excluding Generation)		207.0		187.5
Yankee Gas		45.4		28.8
Other		0.5		0.2
Total Distribution		252.9		216.5
PSNH Generation:				
Clean Air Project		50.8		81.3
Other		7.3		12.9
Total PSNH Generation		58.1		94.2
WMECO Generation		0.6		0.7
Total Distribution Segment	$	311.6	$	311.4

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

PSNH's Clean Air Project is a wet scrubber project under construction at its Merrimack coal station, the cost of which will be recovered through PSNH's ES rates under New Hampshire law. We expect the project to cost approximately $430 million, including capitalized interest and equity returns, and the project should be fully complete by mid-2012. The project is currently ahead of schedule with operational testing to occur in the second half of 2011 and we believe a significant portion could be operational by the end of 2011.

Since inception of the project, PSNH has capitalized $347.4 million associated with this project, of which $51 million was capitalized in the first half of 2011. Construction of the project was approximately 85 percent complete as of June 30, 2011.

On August 12, 2009, the DPU approved a stipulation agreement between WMECO and the Massachusetts Attorney General concerning WMECO's proposal, under the Massachusetts Green Communities Act, to install 6 MW of solar energy generation in its service territory at an estimated cost of $41 million by the end of 2012. In October 2010, WMECO completed construction of a 1.8 MW solar generation facility on a site in Pittsfield, Massachusetts. The full cost of this project was approximately $9.4 million, all of which WMECO had capitalized as of December 31, 2010. In May 2011, WMECO commenced development of a 2.2 MW solar generation facility on a 12-acre brownfield site in Springfield, Massachusetts. The project is expected to be complete by the end of 2011. WMECO is continuing its evaluation of sites suitable for fulfilling the remainder of the authorized 6 MW of capacity.

In April 2010, Yankee Gas commenced construction of its WWL Project, a 16-mile natural gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of its LNG plant. The project is expected to cost $57.6 million. Construction during 2010, which cost $26.6 million, included the completion of Phase I, a seven-mile segment of pipeline connecting the Cheshire and Wallingford distribution systems, and four miles of Phase II. The remainder of the Phase II pipeline construction (approximately five miles) and the expansion of the vaporization capacity of the LNG facility are expected to be completed by the fourth quarter of 2011. Construction of the project was approximately 75 percent complete as of June 30, 2011 and is currently on schedule. Approximately $13.1 million of WWL Project expenditures were capitalized in the first half of 2011.

Transmission Rate Matters

Transmission - Wholesale Rates: NU's transmission rates recover its total transmission revenue requirements, ensuring that we recover all regional and local revenue requirements for providing transmission service. These rates provide for annual reconciliations to actual costs. The difference between billed and actual costs are deferred for future recovery from, or refund to, customers. As of June 30, 2011, NU was in a total net overrecovery position of $19.6 million, which will be refunded to customers in June 2012. Of this amount, CL&P and WMECO were in an overrecovery position of $18.9 million and $2.9 million, respectively, and PSNH was in an underrecovery position of $2.2 million.

NEEWS Incentives: On June 28, 2011, FERC denied a motion by several New England states to reconsider the financial incentives FERC had granted the vast majority of NEEWS investments in 2008. Those incentives included a 125-basis point adder to FERC s base New England transmission ROE, cash recovery of earnings and interest on NEEWS investments while the projects are under construction, and recovery of prudently incurred costs on projects that are abandoned.

Legislative Matters

2010 and 2011 Connecticut Legislation: In May 2010, the Connecticut Legislature approved a state budget for the 2011 fiscal year, which called for the issuance by the state of Connecticut of up to $760 million of economic recovery revenue bonds that would be repaid over eight years. On September 29, 2010, the DPUC approved a financing order for the bonds, but due primarily to legal challenges the bonds were never issued. On June 21, 2011, Governor Malloy signed legislation approving the state budget for the 2012 fiscal year that revoked the authorization for the state to issue the economic recovery revenue bonds. As a result of this change in legislation, on July 1, 2011 customer bills reflected the absence of an increase to rates of approximately $0.0038 per KWh, as the Economic Transition Charge was terminated on June 30, 2011, and was not replaced by the charge associated with the economic recovery revenue bonds.

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

2011 New Hampshire Legislation: On March 30, 2011, the New Hampshire House of Representatives approved House Bill 648, which would preclude non-reliability projects, such as Northern Pass, from using eminent domain to acquire property for construction of transmission lines. On June 2, 2011, the New Hampshire Senate voted to send House Bill 648 back to the Senate Judiciary Committee for further study. The Senate Judiciary Committee is not expected to report on House Bill 648 until its next session, which resumes in January 2012.

Regulatory Developments and Rate Matters

CL&P, PSNH, WMECO and Yankee Gas' rates are set by the respective state regulatory commissions and provide provisions allowing for rate change mechanisms that are adjusted periodically. Other than as described below, for the three and six months ended June 30, 2011, changes made to the CL&P, PSNH and WMECO rates did not have a material impact on their earnings, financial position, or cash flows. For further information, see "Regulatory Developments and Rate Matters" included in our 2010 Form 10-K.

NSTAR Merger Approvals:

Federal: On January 4, 2011, we received approval from the FCC, which was extended on June 20, 2011 to January 7, 2012, and on February 10, 2011, the applicable Hart-Scott-Rodino waiting period expired. On July 6, 2011, we received FERC approval on the merger. We are still awaiting approval from the Nuclear Regulatory Commission.

Massachusetts: On November 24, 2010, NU and NSTAR filed a joint petition requesting the DPU s approval of their proposed merger. On March 10, 2011, the DPU issued an order that modified the standard of review to be applied in the review of mergers involving Massachusetts utilities from a "no net harm" standard to a "net benefits" standard, meaning that the companies must demonstrate that the proposed transaction provides benefits that outweigh the costs. Applicable state law provides that mergers of Massachusetts utilities and their respective holding companies must be "consistent with the public interest." The order states that the DPU will continue to flexibly apply the factors established by case law and statute. NU and NSTAR filed supplemental testimony and a net benefit analysis with the DPU on April 8, 2011, estimating post-transaction net savings of approximately $780 million in the first 10 years following the closing of the merger and provide other customer benefits. An effective date for the merger of October 1, 2011 was used in the development of the net benefit study that was filed with the DPU. Evidentiary hearings began July 6, 2011 and were completed on July 28, 2011, with final briefs due to be filed on September 19, 2011. On July 15, 2011, the Massachusetts Department of Energy Resources filed a motion for a stay of the proceedings. On July 21, 2011, NU and NSTAR filed a response objecting to this motion. We expect a ruling on the merger from the DPU in the fourth quarter of 2011.

Connecticut: In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, had petitioned the DPUC to reconsider its earlier view from November 2010 that it lacked jurisdiction. On June 1, 2011, the DPUC issued a final decision stating that it lacked jurisdiction over the merger. Legislation proposing to give the DPUC jurisdiction over certain types of transactions, including the merger, was never raised in the state Senate or House of Representatives after it received a joint favorable recommendation from the Connecticut Joint Legislative Energy and Technology Committee in March 2011. On June 30, 2011, the Office of Consumer Counsel filed an appeal of the DPUC's final decision. NRG Energy, Inc. (NRG) and the New England Power Generators Association (NEPGA) filed similar appeals on July 1, 2011 and July 14, 2011, respectively. In addition, both NRG and NEPGA filed petitions with the Connecticut Superior Court on July 12, 2011 and July 21, 2011, respectively, requesting a declaratory ruling that the DPUC (now PURA) has jurisdiction over the merger.

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

Maine: We asked Maine regulators alternatively to waive jurisdiction over the merger or to approve the merger. Although neither NU nor NSTAR subsidiaries serve any retail customers in Maine, PSNH owns transmission assets in the state that are subject to the jurisdiction of the Maine Public Utilities Commission. On May 10, 2011, the Maine Public Utilities Commission rejected the waiver request, but approved the merger, subject to FERC approval, which we received on July 6, 2011.

Federal:

EPA Proposed Air Toxic Standard: On March 16, 2011, the EPA issued a proposed rule that would reduce emissions of hazardous air pollutants from new and existing coal- and oil-fired electric generating units. The proposed rule would establish emission limits for mercury, arsenic and other hazardous air pollutants from coal- and oil-fired units. The proposed rule would be the first to implement a nationwide emissions standard for hazardous air pollutants across all electric generating units, providing utility companies up to four years to meet the requirements. PSNH owns and operates approximately 1,000 MW of fossil electric generating units, subject to this proposed rule, including the Merrimack, Newington and Schiller stations. We believe the Clean Air Project at our Merrimack coal station, in addition to existing technology, positions the facility to meet the minimum requirements in the proposed rule. A review of the potential impact of this proposal on our other PSNH units is not yet complete. The EPA expects the proposed ruling will be finalized by mid-November 2011.

Connecticut - Yankee Gas:

Distribution Rates: On June 29, 2011 the DPUC (now PURA) issued a final decision in the Yankee Gas rate proceeding, which authorized a rate reduction of $0.5 million effective July 20, 2011 and an incremental increase of $6.7 million effective July 1, 2012. The final decision approved a regulatory ROE of 8.83 percent, based on a capital structure of 52.2 percent common equity and 47.8 percent debt, approved Yankee Gas WWL Project, and also allowed for an increase in annual spending for bare steel and cast iron pipe replacement funding, at an amount equal to that proposed by Yankee Gas. On July 14, 2011, Yankee Gas filed a motion for reconsideration with the PURA in regards to certain items, including the disallowance of its proposal to reduce ADIT by the tax effect of net operating loss. On August 2, 2011, the PURA issued a draft decision, which would grant Yankee Gas' request for reconsideration and reopen the case on the ADIT issue. A hearing has been scheduled for August 16, 2011.

New Hampshire:

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

Critical Accounting Policies and Estimates Update

The preparation of financial statements in conformity with GAAP requires management to make estimates, assumptions and at times difficult, subjective or complex judgments. Changes in these estimates, assumptions and judgments, in and of themselves, could materially impact our financial position, results of operations or cash flows. Our management communicates to and discusses with our Audit Committee of the Board of Trustees all critical accounting policies and estimates. The accounting policies and estimates that we believed were the most critical in nature were reported in our 2010 Form 10-K. There have been no material changes with regard to these critical accounting policies and estimates.

Other Matters

Environmental Matters: Refer to Note 8A, "Commitments and Contingencies Environmental Matters," to the unaudited condensed consolidated financial statements for discussion of the HWP environmental remediation contingency.

Contractual Obligations and Commercial Commitments: There have been no additional contractual obligations identified and no material changes with regard to the contractual obligations and commercial commitments previously disclosed in our 2010 Form 10-K.

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

RESULTS OF OPERATIONS NORTHEAST UTILITIES AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the unaudited condensed consolidated statements of income for NU included in this Quarterly Report on Form 10-Q for the three and six months ended June 30, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended June 30,				Operating Revenues and Expenses For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 1,047.5	$ 1,111.4	$ (63.9)	(5.7)%	$ 2,282.7	$ 2,450.8	$ (168.1)	(6.9)%
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	340.3	442.2	(101.9)	(23.0)	814.4	1,045.6	(231.2)	(22.1)
Other Operating Expenses	262.8	206.7	56.1	27.1	514.8	454.9	59.9	13.2
Maintenance	78.8	66.8	12.0	18.0	146.6	112.4	34.2	30.4
Depreciation	73.7	79.1	(5.4)	(6.8)	147.6	157.7	(10.1)	(6.4)
Amortization of Regulatory Assets, Net	17.3	8.9	8.4	94.4	51.6	0.6	51.0	(a)
Amortization of Rate Reduction Bonds	17.1	55.0	(37.9)	(68.9)	34.4	114.6	(80.2)	(70.0)
Taxes Other Than Income Taxes	79.4	74.4	5.0	6.7	167.8	160.0	7.8	4.9
Total Operating Expenses	869.4	933.1	(63.7)	(6.8)	1,877.2	2,045.8	(168.6)	(8.2)
Operating Income	$ 178.1	$ 178.3	$ (0.2)	(0.1)%	$ 405.5	$ 405.0	$ 0.5	0.1 %

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

Operating Revenues

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Electric Distribution	$ 794.4	$ 884.5	$ (90.1)	(10.2)%	$ 1,686.0	$ 1,884.5	$ (198.5)	(10.5)%
Natural Gas Distribution	78.4	73.5	4.9	6.7	258.6	245.2	13.4	5.5
Total Distribution	872.8	958.0	(85.2)	(8.9)	1,944.6	2,129.7	(185.1)	(8.7)
Transmission	152.1	154.2	(2.1)	(1.4)	310.3	307.9	2.4	0.8
	1,024.9	1,112.2	(87.3)	(7.8)	2,254.9	2,437.6	(182.7)	(7.5)

Total Regulated Companies								
Other and Eliminations	22.6	(0.8)	23.4	(a)	27.8	13.2	14.6	(a)
NU	$ 1,047.5	$ 1,111.4	$ (63.9)	(5.7)%	$ 2,282.7	$ 2,450.8	$ (168.1)	(6.9)%

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

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

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2011	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase**	**Percent**
Retail Electric Sales in GWh	7,966	8,068	(102)	(1.3)%	16,671	16,516	155	0.9 %
Firm Natural Gas Sales in Million Cubic Feet	8,480	6,941	1,539	22.2 %	27,864	23,529	4,335	18.4 %
Firm Natural Gas Sales (Net of Special Contracts) in Million Cubic Feet	6,450	5,027	1,423	28.3 %	23,390	19,274	4,116	21.4 %

Our Operating Revenues decreased for the three months ended June 30, 2011 as compared to the same period in 2010 due primarily to:

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Lower electric distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower energy and supply-related costs ($91.4 million), lower CL&P CTA revenues ($41.9 million), lower wholesale revenues ($15.3 million) and lower retail other revenues ($9 million), partially offset by higher retail transmission revenues ($8.9 million) and higher other tracked revenues ($5.8 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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The portion of electric distribution revenues that impacts earnings increased $32.4 million due primarily to the rate case decisions received that were effective during the first half of 2011. An increase in natural gas revenues was due primarily to an increase in sales volume related to the colder than normal weather in 2011. Firm natural gas sales increased 22.2 percent in the second quarter of 2011 compared to the same period in 2010. Partially offsetting the increase in firm revenues was a decrease in cost of fuel, as fuel costs are fully recovered in revenues from sales to our customers.

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

Our Operating Revenues decreased for the first half of 2011 as compared to the same period in 2010 due primarily to:

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Lower electric distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower energy and supply-related costs ($201.2 million), lower CL&P CTA revenues ($81.3 million), lower wholesale revenues ($31.8 million) and lower retail other revenues ($18.7 million), partially offset by higher retail transmission revenues ($26.2 million) and higher other tracked revenues ($13.9 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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The portion of electric distribution revenues that impacts earnings increased $87.2 million due primarily to the rate case decisions received that were effective during the first half of 2011. An increase in natural gas revenues was due primarily to an increase in sales volume related to the colder than normal weather in 2011. Firm natural gas sales increased 18.4 percent in the first half of 2011 compared to the same period in 2010. Partially offsetting the increase in firm revenues was a decrease in cost of fuel, as fuel costs are fully recovered in revenues from sales to our customers.

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

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to the following:

(Millions of Dollars)		**Three Months Ended**		**Six Months Ended**
Lower GSC supply costs and purchased power contract costs, partially offset by higher other costs at CL&P	$	(83.4)	$	(190.9)

ES customer migration to third party electric suppliers, partially offset by lower ES customer retail sales at PSNH		(14.0)		(30.6)
Lower basic service supply costs at WMECO		(4.1)		(7.6)
Higher unregulated business wholesale contract mark-to-market gains and other		(0.4)		(2.1)
	$	(101.9)	$	(231.2)

Other Operating Expenses

Other Operating Expenses increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to:

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Higher distribution and transmission segment expenses ($23.8 million and $22.3 million, respectively) were due primarily to higher costs that are recovered through distribution tracking mechanisms that have no earnings impact ($15.2 million and $9.6 million, respectively), such as retail transmission, RMR and customer service expenses. In addition, there were higher electric distribution expenses ($8.8 million and $10 million, respectively) and higher natural gas expenses ($3.3 million and $6.1 million, respectively), including higher pension costs and higher administrative and general expenses. Partially offsetting these increases were lower transmission segment expenses ($3 million and $2.3 million, respectively). These expenses include amounts that eliminate in consolidation which decreased by $22.2 million and $6.8 million, respectively.

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Higher NU parent and other companies expenses ($10.1 million and $30.7 million, respectively) were due primarily to higher costs in 2011 related to NU's proposed merger with NSTAR and higher pension costs.

Maintenance

Maintenance increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to the partial amortization in 2011 of the allowed regulatory deferral, which was recorded in maintenance expense in 2010, as a result of the June 30, 2010 CL&P rate case decision ($10.9 million and $21.7 million, respectively) and higher distribution segment routine overhead line expenses ($0.2 million and $14.2 million, respectively) primarily related to storm costs that did not meet the minimum requirement for regulatory deferral, offset by lower maintenance costs at PSNH s generation business ($1.4 million) in the first half of 2011 as compared to the same period in 2010.

Depreciation

Depreciation decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to a lower depreciation rate being used at CL&P as a result of the distribution rate case decision that was effective July 1, 2010. Partially offsetting this decrease are higher depreciation rates being used at PSNH and WMECO in the first half of 2011 as a result of distribution rate case decisions that were effective during the first half of 2011 and higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, increased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to lower CTA transition costs ($49.6 million) partially offset by lower retail CTA revenue ($37.6 million) at CL&P and increases in TCAM amortization ($15.9 million) and ES amortization ($2.8 million) at PSNH. Partially offsetting these increases was lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes at CL&P ($9.1 million).

Amortization of Regulatory Assets, Net, increased for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to the absence in 2011 of the impact of the 2010 Healthcare Act related to income taxes ($24 million), lower CTA transition costs ($106.3 million) partially offset by lower retail CTA revenue ($74.4 million) at CL&P and increases in TCAM amortization ($19 million) and ES amortization ($16.3 million) at PSNH. Partially offsetting these increases was lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes at CL&P ($18.9 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due to the maturity of CL&P s RRBs in December 2010 and lower principal balances on the remaining PSNH and WMECO RRBs outstanding.

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes for the three and six months ended June 30, 2011 as compared to the same period in 2010 was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to our capital program and an increase in the tax rate, offset by a decrease in the Connecticut Gross Earnings Tax primarily due to lower transmission segment revenues and lower CTA revenues in 2011 as compared to 2010.

Interest Expense

	For the Three Months Ended June 30,				**For the Six Months Ended June 30,**			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 57.0	$ 58.5	$ (1.5)	(2.6)%	$ 114.4	$ 115.8	$ (1.4)	(1.2)%
Interest on RRBs	2.3	5.6	(3.3)	(58.9)	4.9	12.3	(7.4)	(60.2)
Other Interest	2.9	3.1	(0.2)	(6.5)	1.5	6.4	(4.9)	(76.6)
	$ 62.2	$ 67.2	$ (5.0)	(7.4)%	$ 120.8	$ 134.5	$ (13.7)	(10.2)%

Interest Expense decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to the resolution of state tax matters concerning the calculation of interest on outstanding amounts in the first quarter of 2011, which resulted in a reduction in Other Interest. There was also lower Interest on RRBs in

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

Other Income, Net

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 7.3	$ 1.6	$ 5.7	(a)%	$ 17.6	$ 9.6	$ 8.0	83.3 %

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

Other Income, Net increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to higher investment and interest income ($6 million and $7.1 million, respectively) and higher AFUDC related to equity funds ($2.5 million and $4.9 million, respectively).

Income Tax Expense

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 44.5	$ 39.4	$ 5.1	12.9 %	$ 108.1	$ 119.2	$ (11.1)	(9.3)%

Income Tax Expense increased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings ($3.7 million).

Income Tax Expense decreased for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to the absence of 2010 Healthcare Act impacts ($27.6 million) and a decrease in the items that directly impact our tax return as a result of regulatory requirements ("flow-through" items) ($3.7 million); partially offset by higher pre-tax earnings ($18.6 million).

RESULTS OF OPERATIONS THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the unaudited condensed consolidated statements of income for CL&P included in this Quarterly Report on Form 10-Q for the three and six months ended June 30, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended June 30,				Operating Revenues and Expenses For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 608.0	$ 707.9	$ (99.9)	(14.1)%	$ 1,281.7	$ 1,502.9	$ (221.2)	(14.7)%
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	207.2	290.6	(83.4)	(28.7)	462.5	653.4	(190.9)	(29.2)
Other Operating Expenses	139.3	120.3	19.0	15.8	273.6	255.1	18.5	7.3
Maintenance	41.9	32.8	9.1	27.7	82.7	54.6	28.1	51.5
Depreciation	38.4	47.9	(9.5)	(19.8)	77.9	95.5	(17.6)	(18.4)
Amortization of Regulatory Assets, Net	13.7	20.6	(6.9)	(33.5)	33.0	22.3	10.7	48.0
Amortization of Rate Reduction Bonds	-	38.9	(38.9)	(100.0)	-	82.2	(82.2)	(100.0)
Taxes Other Than Income Taxes	52.7	50.6	2.1	4.2	111.2	108.1	3.1	2.9
Total Operating Expenses	493.2	601.7	(108.5)	(18.0)	1,040.9	1,271.2	(230.3)	(18.1)
Operating Income	$ 114.8	$ 106.2	$ 8.6	8.1 %	$ 240.8	$ 231.7	$ 9.1	3.9 %

Operating Revenues

CL&P's retail electric sales were as follows:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2011	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Increase**	**Percent**
Retail Electric Sales in GWh	5,250	5,337	(87)	(1.6)%	11,026	10,929	97	0.9 %

CL&P's Operating Revenues decreased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to:

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A $114.4 million decrease in electric distribution revenues related to the portions that are included in DPUC (now PURA) approved tracking mechanisms that track and recover certain incurred costs that do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower GSC and supply-related FMCC revenues ($74.1 million), lower CTA revenues ($40.4 million), lower wholesale revenues ($16 million) and lower retail other revenues ($8.8 million). These lower revenues were partially offset by higher retail transmission revenues ($3.6 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation increased distribution revenues by $22 million. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. The lower GSC and supply-related FMCC revenues were due primarily to lower customer rates resulting from lower average supply prices and additional customer migration to third party electric suppliers in the second quarter of 2011, as compared to the second quarter of 2010.

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The portion of electric distribution revenues that impacts earnings increased $20.3 million due primarily to the retail rate increase effective January 1, 2011, partially offset by a 1.6 percent decrease in retail electric sales volume in the second quarter of 2011, as compared to the second quarter of 2010.

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A $5.8 million decrease in transmission segment revenues was due primarily to a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year. This decrease was partially offset by increased transmission segment revenues due to the increased level of investment in the transmission infrastructure.

CL&P's Operating Revenues decreased for the first half of 2011, as compared to the same period in 2010, due primarily to:

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A $274 million decrease in electric distribution revenues related to the portions that are included in PURA approved tracking mechanisms that track and recover certain incurred costs that do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower GSC and supply-related FMCC revenues ($171.4 million), lower CTA revenues ($79.3 million), lower wholesale revenues ($34.5 million) and lower retail other revenues ($18.1 million). These lower revenues were partially offset by higher retail transmission revenues ($14.1 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation increased distribution revenues by $15.1 million. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. The lower

GSC and supply-related FMCC revenues were due primarily to lower customer rates resulting from lower average supply prices and additional customer migration to third party electric suppliers in the first half of 2011, as compared to the first half of 2010.

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The portion of electric distribution revenues that impacts earnings increased $58.6 million in the first half of 2011, as compared to the same period in 2010 due primarily to the retail rate increase effective January 1, 2011.

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A $5.8 million decrease in transmission segment revenues was due primarily to a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year. This decrease was partially offset by increased transmission segment revenues due to the increased level of investment in the transmission infrastructure.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to the following:

(Millions of Dollars)		**Three Months Ended**		**Six Months Ended**
GSC Supply Costs	$	(73.1)	$	(175.1)
Purchased Power Contracts		(15.4)		(33.7)
Deferred Fuel Costs		(1.1)		8.4
Other		6.2		9.5
	$	(83.4)	$	(190.9)

The decrease in GSC supply costs was due primarily to lower average supply prices and additional customer migration to third party electric suppliers for the three and six months ended June 30, 2011, as compared to the same periods in 2010. These GSC supply costs are the contractual amounts CL&P must pay to various suppliers that have been awarded the right to supply SS and LRS load through a competitive solicitation process. These costs are included in PURA approved tracking mechanisms and do not impact earnings.

Other Operating Expenses

Other Operating Expenses increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, as a result of higher costs that are recovered through distribution tracking mechanisms and have no earnings impact ($20.8 million and 13.8 million, respectively) including higher retail transmission ($26.1 million and $28.9 million, respectively), higher distribution segment expenses ($1.4 million and $7.8 million, respectively) mainly as a result of higher administrative and general expenses, including higher pension costs. Partially offsetting these increases were lower transmission segment expenses ($2.8 million and $2 million, respectively).

Maintenance

Maintenance increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to the partial amortization in 2011 of the allowed regulatory deferral, which was recorded in maintenance expense in 2010, as a result of the June 30, 2010 rate case decision ($10.9 million and $21.7 million, respectively) and higher distribution vegetation management expenses ($1.5 million and $1.3 million, respectively). In addition, there were higher distribution segment routine overhead line expenses for the first half of 2011 ($4.6

million) primarily related to storm costs that did not meet the minimum requirement for regulatory deferral.

Depreciation

Depreciation decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to a lower depreciation rate being used as a result of the distribution rate case decision that was effective July 1, 2010, partially offset by higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, decreased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to lower amortization of the SBC balance ($9.3 million) and lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes ($9.1 million). Partially offsetting these decreases are lower CTA transition costs ($49.6 million) partially offset by lower retail CTA revenue ($37.6 million).

Amortization of Regulatory Assets, Net, increased for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily lower CTA transition costs ($106.3 million) partially offset by lower retail CTA revenue ($74.4 million), and the absence in 2011 of the impact of the 2010 Healthcare Act related to income taxes ($11.1 million). Partially offsetting these increases is lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes ($18.9 million) and lower amortization of the SBC balance ($13 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due to the maturity of RRBs in December 2010.

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes for the three and six months ended June 30, 2011 as compared to the same period in 2010 was due primarily to an increase in property taxes related to an increase in Property, Plant and Equipment related to CL&P s capital program and an increase in the tax rate, offset by a decrease in the Connecticut Gross Earnings Tax primarily due to lower transmission segment revenues and lower CTA revenues in 2011 as compared to 2010.

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Interest Expense

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	2011	2010	Increase/ (Decrease)	Percent	2011	2010	Increase/ (Decrease)	Percent
Interest on Long-Term Debt	$ 33.4	$ 33.6	$ (0.2)	(0.6) %	$ 66.8	$ 67.2	$ (0.4)	(0.6) %
Interest on RRBs	-	2.3	(2.3)	(100.0)	-	5.3	(5.3)	(100.0)
Other Interest	0.9	1.3	(0.4)	(30.8)	(2.7)	3.2	(5.9)	(a)
	$ 34.3	$ 37.2	$ (2.9)	(7.8) %	$ 64.1	$ 75.7	$ (11.6)	(15.3) %

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

Interest Expense decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to the resolution of state tax matters concerning the calculation of interest on outstanding amounts in the first quarter of 2011, which resulted in a reduction in Other Interest and the absence of Interest on RRBs in 2011 as CL&P's RRBs matured in December 2010.

Other Income, Net

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	2011	2010	Increase/ (Decrease)	Percent	2011	2010	Increase/ (Decrease)	Percent
Other Income, Net	$ 2.1	$ 0.7	$ 1.4	(a)	$ 6.7	$ 5.7	$ 1.0	17.5 %

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

Other Income, Net increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to higher investment and interest income.

Income Tax Expense

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	2011	2010	Increase/ (Decrease)	Percent	2011	2010	Increase/ (Decrease)	Percent
Income Tax Expense	$ 29.9	$ 25.6	$ 4.3	16.8 %	$ 66.4	$ 69.1	$ (2.7)	(3.9)%

Income Tax Expense increased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings.

Income Tax Expense decreased for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to the absence of 2010 Healthcare Act impacts ($14.4 million) and lower flow through items ($2 million), partially offset by higher pre-tax earnings ($12.3 million).

LIQUIDITY

CL&P had cash flows provided by operating activities in the first half of 2011 of $359 million, compared with operating cash flows of $234.7 million in the first half of 2010 (first half 2010 amounts are net of RRB payments, which are included in financing activities). The improved cash flows in 2011 were due primarily to the impact of the DPUC (now PURA) June 30, 2011 distribution rate case decision, which increased CL&P s customer rates effective January 1, 2011, a net positive cash flow impact of approximately $69 million largely attributable to accelerated depreciation tax benefits, and the absence of payments in the first half of 2011 related to 2010 major storm costs. We continue to project cash flows provided by operating activities at CL&P of between $600 million and $650 million in 2011.

Cash capital expenditures included on the accompanying unaudited condensed consolidated statements of cash flows do not include amounts incurred on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. CL&P's cash capital expenditures totaled $202 million for the six months ended June 30, 2011, compared with $191.7 million for the six months ended June 30, 2010.

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

Financing activities for the six months ended June 30, 2011 included $168.7 million in common dividends paid to NU parent.

RESULTS OF OPERATIONS PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the unaudited condensed consolidated statements of income for PSNH included in this Quarterly Report on Form 10-Q for the three and six months ended June 30, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended June 30,				Operating Revenues and Expenses For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 240.2	$ 238.3	$ 1.9	0.8 %	$ 509.7	$ 496.9	$ 12.8	2.6 %
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	69.3	83.3	(14.0)	(16.8)	156.5	187.1	(30.6)	(16.4)
Other Operating Expenses	54.3	56.1	(1.8)	(3.2)	110.7	119.2	(8.5)	(7.1)
Maintenance	29.9	25.6	4.3	16.8	48.6	41.6	7.0	16.8
Depreciation	18.1	16.0	2.1	13.1	36.0	32.0	4.0	12.5
Amortization of Regulatory Assets/(Liabilities), Net	2.5	(11.6)	14.1	(a)	18.0	(17.3)	35.3	(a)
Amortization of Rate Reduction Bonds	13.0	12.2	0.8	6.6	26.1	24.6	1.5	6.1
Taxes Other Than Income Taxes	15.2	13.3	1.9	14.3	28.9	26.4	2.5	9.5
Total Operating Expenses	202.3	194.9	7.4	3.8	424.8	413.6	11.2	2.7
Operating Income	$ 37.9	$ 43.4	$ (5.5)	(12.7)%	$ 84.9	$ 83.3	$ 1.6	1.9 %

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

Operating Revenues:

PSNH's retail electric sales were as follows:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2011	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Increase**	**Percent**
Retail Electric Sales in GWh	1,849	1,855	(6)	(0.4)%	3,833	3,787	46	1.2 %

PSNH's Operating Revenues increased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to:

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The portion of electric distribution revenues that impacts earnings increased $9.7 million in the second quarter of 2011 as compared to the second quarter of 2010 due primarily to the retail rate increase effective July 1, 2010.

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A $8.8 million decrease in distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. This decrease primarily related to lower purchased fuel and power costs ($11.9 million), mostly related to ES customer migration to third party electric suppliers. These lower revenues were offset by higher retail transmission revenues ($5 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers and undercollections to be recovered from customers in future periods.

PSNH's Operating Revenues increased for the first half of 2011, as compared to the same period in 2010, due primarily to:

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The portion of electric distribution revenues that impacts earnings increased $22.7 million in the first half of 2011 as compared to the first half of 2010 due primarily to the retail rate increase effective July 1, 2010.

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A $2.9 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

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A $12.9 million decrease in distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. This decrease primarily related to lower purchased fuel and power costs ($20 million), mostly related to ES customer migration to third party electric suppliers. These lower revenues were offset by higher retail transmission revenues ($11.2 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers and undercollections to be recovered from customers in future periods. In addition, transmission segment intracompany billings to the distribution segment that are eliminated in consolidation decreased distribution revenues by $4.3 million.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to a slight increase in the level of ES customer migrating to third party electric suppliers and lower retail sales for PSNH's remaining ES customers.

Other Operating Expenses

Other Operating Expenses decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, as a result of lower retail transmission expenses ($7.1 million and $8.4 million, respectively), partially offset by higher distribution segment expenses ($7.9 million and $2.9 million), mainly as a result of higher administrative and general expenses ($3.3 million and $1.3 million, respectively).

Maintenance

Maintenance increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to higher distribution segment routine overhead line expenses ($4.7 million and $10.4 million, respectively) primarily related to storm costs that did not meet the minimum requirement for regulatory deferral, offset by lower vegetation management costs ($0.9 million and $1.6 million, respectively) and lower generation maintenance costs ($1.4 million) in the first half of 2011 as compared to the same period in 2010.

Depreciation

Depreciation increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to a higher depreciation rate being used as a result of the distribution rate case decision that was effective July 1, 2010 and higher utility plant balances resulting from completed construction projects placed into service related to PSNH's capital programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net increased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to an increase in TCAM amortization ($15.9 million) and ES amortization ($2.8 million).

Amortization of Regulatory Assets/(Liabilities), Net increased for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to an increase in ES amortization ($16.7 million) and TCAM amortization ($19 million) and the absence in 2011 of the impact of the 2010 Healthcare Act related to income taxes ($4.8 million).

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes for the three and six months ended June 30, 2011 as compared to the same period in 2010 was due primarily to an increase in property taxes related to an increase in Property, Plant and Equipment related to PSNH s capital program and an increase in the tax rate.

Interest Expense

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	2011	2010	Increase/ (Decrease)	Percent	2011	2010	Increase/ (Decrease)	Percent
Interest on Long-Term Debt	$ 8.3	$ 9.3	$ (1.0)	(10.8)%	$ 17.0	$ 18.8	$ (1.8)	(9.6)%
Interest on RRBs	1.7	2.5	(0.8)	(32.0)	3.6	5.2	(1.6)	(30.8)
Other Interest	0.4	0.2	0.2	100.0	0.3	0.4	(0.1)	(25.0)
	$ 10.4	$ 12.0	$ (1.6)	(13.3)%	$ 20.9	$ 24.4	$ (3.5)	(14.3)%

Interest Expense decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to lower Interest on Long-Term Debt due to higher AFUDC borrowed funds related to PSNH's Clean Air Project and lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	2011	2010	Increase/ (Decrease)	Percent	2011	2010	Increase/ (Decrease)	Percent
Other Income/(Loss), Net	$ 4.4	$ (0.2)	$ 4.6	(a)	$ 8.8	$ 2.2	$ 6.6	(a)

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

Other Income, Net increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to higher investment and interest income ($2.6 million and $3 million, respectively) and higher AFUDC related to equity funds ($2 million and $3.6 million, respectively).

Income Tax Expense

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	2011	2010	Increase/ (Decrease)	Percent	2011	2010	Increase/ (Decrease)	Percent
Income Tax Expense	$ 10.2	$ 9.6	$ 0.6	6.3 %	$ 23.7	$ 23.7	$ -	- %

Income Tax Expense did not vary for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings impacts ($5.7 million) offset by the absence of 2010 Healthcare Act impacts ($6.5 million).

LIQUIDITY

PSNH had cash flows provided by operating activities in the first half of 2011 of $130.5 million, compared with operating cash flows of $84.3 million in the first half of 2010 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows were due primarily to the impact of PSNH s 2010 distribution rate case settlement, which increased PSNH customer rates effective July 1, 2010, a net positive cash flow impact of approximately $11 million largely attributable to accelerated depreciation tax benefits, and the absence of payments in the first half of 2011 related to 2010 major storm costs. In addition, in 2011 PSNH began collecting on the ES tracking mechanism's 2010 underrecoveries, creating a favorable cash flow impact. Offsetting these benefits was a second quarter 2011 contribution into the NU Pension Plan of $15.2 million.

RESULTS OF OPERATIONS WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

The following table provides the amounts and variances in operating revenues and expense line items for the unaudited condensed consolidated statements of income for WMECO included in this Quarterly Report on Form 10-Q for the three and six months ended June 30, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended June 30,				Operating Revenues and Expenses For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 98.4	$ 92.5	$ 5.9	6.4 %	$ 205.1	$ 192.7	$ 12.4	6.4 %
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	32.6	36.7	(4.1)	(11.2)	72.8	80.4	(7.6)	(9.5)
Other Operating Expenses	26.4	23.1	3.3	14.3	52.6	46.3	6.3	13.6
Maintenance	4.2	5.3	(1.1)	(20.8)	9.0	9.9	(0.9)	(9.1)
Depreciation	6.6	5.9	0.7	11.9	13.0	11.8	1.2	10.2
Amortization of Regulatory Assets/(Liabilities), Net	1.8	(0.7)	2.5	(a)	1.2	(2.3)	3.5	(a)
Amortization of Rate Reduction Bonds	4.1	3.8	0.3	7.9	8.2	7.7	0.5	6.5
Taxes Other Than Income Taxes	4.2	4.1	0.1	2.4	8.8	8.2	0.6	7.3
Total Operating Expenses	79.9	78.2	1.7	2.2	165.6	162.0	3.6	2.2
Operating Income	$ 18.5	$ 14.3	$ 4.2	29.4 %	$ 39.5	$ 30.7	$ 8.8	28.7 %

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

Operating Revenues

WMECO's retail electric sales were as follows:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2011	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Increase**	**Percent**
Retail Electric Sales in GWh	871	879	(8)	(0.9)%	1,819	1,808	11	0.6 %

WMECO's Operating Revenues increased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to:

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The portion of electric distribution revenues that impacts earnings increased $2.5 million due primarily to the retail rate increase effective February 1, 2011.

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

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A $2.8 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

WMECO's Operating Revenues increased for the first half of 2011, as compared to the same period in 2010, due primarily to:

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The portion of electric distribution revenues that impacts earnings increased $5.8 million due primarily to the retail rate increase effective February 1, 2011.

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Amounts related to distribution revenues that did not impact earnings and are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs increased by $1.2 million in the first half of 2011 compared to the first half of 2010. Included in these amounts are C&LM collections, pension and other trackers. These tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections to be recovered from customers in future periods.

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A $5.3 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to lower basic service supply costs in addition to an increase in the deferral of excess basic service expense over basic service revenue. The basic service supply costs are the contractual amounts WMECO must pay to various suppliers that serve this load after winning a competitive solicitation process. To the extent these costs do not match revenues collected from customers, the DPU allows the difference to be deferred for future collection or refunded to customers. The basic service supply costs decreased due primarily to lower supplier contract rates.

Fuel, Purchased and Net Interchange Power decreased for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to lower basic service supply costs partially offset by a decrease in the deferral of excess basic service expense over basic service revenue. The basic service supply costs decreased due primarily to lower supplier contract rates, partially offset by increased load volumes.

Other Operating Expenses

Other Operating Expenses increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, as a result of higher distribution segment expenses resulting from higher costs that are recovered through distribution tracking mechanisms and have no earnings impact primarily related to an increase in C&LM expenses attributable to the Massachusetts Green Communities Act ($2.3 and $4.9 million, respectively) and higher administrative and general expenses ($1.3 million and $2.9 million, respectively).

Maintenance

Maintenance decreased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to lower distribution segment routine overhead line expenses.

Depreciation

Depreciation increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to a higher depreciation rate being used at WMECO as a result of the distribution rate case decision that was effective February 1, 2011 and higher utility plant balances resulting from completed construction projects placed into service related to WMECO's capital programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net, increased for the three and six months ended June 30, 2011, as compared to the same periods in 2010, due primarily to the absence in 2011 of the impact of the 2010 Healthcare Act related to income taxes and an adjustment related to the low income discount recovery deferral as a result of the rate case decision effective February 1, 2011.

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes for the six months ended June 30, 2011 as compared to the same period in 2010 was due primarily to an increase in property taxes related to an increase in Property, Plant and Equipment related to WMECO s capital program and an increase in the tax rate**.**

Income Tax Expense

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 5.1	$ 3.5	$ 1.6	45.7 %	$ 11.3	$ 10.0	$ 1.3	13.0 %

Income Tax Expense increased for the three months ended June 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings ($1.5 million).

Income Tax Expense increased for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings ($4 million), partially offset by the absence of 2010 Healthcare Act impacts ($2.8 million).

LIQUIDITY

WMECO had cash flows provided by operating activities in the first half of 2011 of $58.1 million, compared with operating cash flows of $15.8 million in the first half of 2010 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows were due primarily to the impact of the DPU distribution rate case decision that was effective February 1, 2011, a net positive cash flow impact of approximately $9 million largely attributable to accelerated depreciation tax benefits, and the absence of payments in the first half of 2011 related to 2010 major storm costs.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

Commodity Price Risk Management: Our Regulated companies enter into energy contracts to serve our customers and the economic impacts of those contracts are passed on to our customers. Accordingly, the Regulated companies have no exposure to loss of future earnings or fair values due to these market risk-sensitive instruments. The remaining unregulated wholesale portfolio held by Select Energy includes contracts that are market risk-sensitive, including a wholesale energy sales contract through 2013 with an agency comprised of municipalities with approximately 0.1 million remaining MWh of supply contract volumes, net of related sales volumes. Select Energy also has a non-derivative energy contract that expires in mid-2012 to purchase output from a generation facility, which is also exposed to market price volatility. As Select Energy's contract volumes are winding down, and as the wholesale energy sales contract is substantially hedged against price risks, we have limited exposure to commodity price risks. We have not entered into any energy contracts for trading purposes.

Sensitivity analysis provides a presentation of the potential loss of future pre-tax earnings and fair values from our market risk-sensitive contracts due to one or more hypothetical changes in commodity price components, or other similar price changes. We have provided this analysis in Part II, Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," in our 2010 Form 10-K, which disclosures are incorporated herein by reference. There have been no additional market or commodity price risks identified and no material changes with regard to the sensitivity analysis previously disclosed in our 2010 Form 10-K.

Other Risk Management Activities

Interest Rate Risk Management: We manage our interest rate risk exposure in accordance with our written policies and procedures by maintaining a mix of fixed and variable rate long-term debt.

Credit Risk Management: Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of our contractual obligations. We serve a wide variety of customers and suppliers that include IPPs, industrial companies, gas and electric utilities, oil and gas producers, financial institutions, and other energy marketers. Margin accounts exist within this diverse group, and we realize interest receipts and payments related to balances outstanding in these margin accounts. This wide customer and supplier mix generates a need for a variety of contractual structures, products and terms that, in turn, require us to manage the portfolio of market risk inherent in those transactions in a manner consistent with the parameters established by our risk management process.

If the respective unsecured debt ratings of NU parent, PSNH or WMECO were reduced to below investment grade by either Moody s or S&P, certain of NU, PSNH and WMECO s contracts would require additional collateral in the form of cash or LOCs to be provided to counterparties and independent system operators. If such an event occurred as of June 30, 2011, NU, PSNH and WMECO would have been required to provide additional cash or LOCs in an aggregate amount of $30.8 million, $6.1 million and $1.5 million, respectively. NU, PSNH and WMECO would have been and remain able to provide that collateral.

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

We have provided additional disclosures regarding interest rate risk management and credit risk management in Part II, Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," in our 2010 Form 10-K, which are incorporated herein by reference. There have been no additional risks identified and no material changes with regard to the items previously disclosed in our 2010 Form 10-K.

ITEM 4.

CONTROLS AND PROCEDURES

Management, on behalf of NU, CL&P, PSNH and WMECO, evaluated the design and operation of the disclosure controls and procedures as of June 30, 2011 to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Securities Exchange Act of 1934 and the rules and regulations of the SEC. This evaluation was made under management's supervision and with management's participation, including the principal executive officers and principal financial officer as of the end of the period covered by this Quarterly Report on Form 10-Q. There are inherent limitations of disclosure controls and procedures, including the possibility of human error and the circumventing or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. The principal executive officers and principal financial officer have concluded, based on their review, that the disclosure controls and procedures of NU, CL&P, PSNH and WMECO are effective to ensure that information required to be disclosed by us in reports filed under the Securities Exchange Act of 1934 (i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and regulations and (ii) is accumulated and communicated to management, including the principal executive officers and principal financial officer, as appropriate to allow timely decisions regarding required disclosures.

There have been no changes in internal controls over financial reporting for NU, CL&P, PSNH and WMECO during the quarter ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1.

LEGAL PROCEEDINGS

We are parties to various legal proceedings. We have identified these legal proceedings in Part I, Item 3, "Legal Proceedings," and elsewhere in our 2010 Form 10-K, and in Part II, Item 1, "Legal Proceedings," in our quarterly report on Form 10-Q for the quarter ended March 31, 2011, which disclosures are incorporated herein by reference. Other than as set forth below, there have been no additional legal proceedings identified and no material changes with regard to the legal proceedings previously disclosed in those filings.

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

ITEM 1A.

RISK FACTORS

We are subject to a variety of significant risks in addition to the matters set forth under "Forward-Looking Statements," in Item 2, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this Quarterly Report on Form 10-Q. We have identified a number of these risk factors in Item 1A, "Risk Factors," in our 2010 Form 10-K, which risk factors are incorporated herein by reference. These risk factors should be considered carefully in evaluating our risk profile. Other than as set forth below, there have been no additional risk factors identified and no material changes with regard to the risk factors previously disclosed in our 2010 Form 10-K.

Our counterparties may not meet their obligations to us or may elect to exercise their termination rights which would adversely affect our earnings.

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

Difficulties in obtaining siting, design or other approvals for major transmission projects, global demand for critical resources or environmental 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 and result in delays or cancellation of our transmission projects. These include the regulatory approval process, environmental and community concerns, design and siting issues and actions of strategic partners. Should any of these factors result in delays or cancellation of major transmission projects, our financial position, results of operations, and cash flows could be adversely affected.

Changes in regulatory or legislative policy and/or regulatory decisions or construction of new generation may delay completion of or displace our planned transmission projects or adversely affect our ability to recover our investments or result in lower than expected rates of return.

Our transmission construction plans could be affected by new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions. Any of such events could cause delays in our construction schedule adversely affecting 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 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 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 level presently anticipated.

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ITEM 2.

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

There were no purchases made by or on behalf of NU or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934) of NU common shares during the quarter ended June 30, 2011.

ITEM 6.

EXHIBITS

Each document described below is incorporated by reference by the registrant(s) listed to the files identified, unless designated with a (*), which exhibits are filed herewith.

Exhibit No.

Description

Listing of Exhibits (NU)

*12

Ratio of Earnings to Fixed Charges

*15

Deloitte & Touche LLP Letter Regarding Unaudited Financial Information

*31

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Northeast Utilities, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*32

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities and David R. McHale, Executive Vice President and Chief Financial Officer of Northeast Utilities, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*101.INS

XBRL Instance Document

*101.SCH

XBRL Taxonomy Extension Schema

*101.CAL

XBRL Taxonomy Extension Calculation

*101.DEF

XBRL Taxonomy Extension Definition

*101.LAB

XBRL Taxonomy Extension Labels

*101.PRE

XBRL Taxonomy Extension Presentation

Listing of Exhibits (CL&P)

*12

Ratio of Earnings to Fixed Charges

*31

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*32

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company and David R. McHale, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

Listing of Exhibits (PSNH)

4.1

Eighteenth Supplemental Indenture dated as of May 1, 2011 between PSNH and U.S. Bank, National Association, as Trustee (Exhibit 4.1 to PSNH Current Report on Form 8-K filed June 2, 2011, File No. 001-06392)

4.2

Composite Amended and Restated Indenture, effective June 1, 2011, between PSNH and U.S. Bank, National Association, as Trustee (included as Schedule C to the Eighteenth Supplemental Indenture filed as Exhibit 4.1 to PSNH Current Report on Form 8-K filed June 2, 2011, File No. 001-06392)

*12

Ratio of Earnings to Fixed Charges

*31

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*32

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire and David R. McHale, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

Listing of Exhibits (WMECO)

*12

Ratio of Earnings to Fixed Charges

*31

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

*32

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company and David R. McHale, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated August 5, 2011

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

NORTHEAST UTILITIES
(Registrant)

/s/

Date: August 5, 2011

By David R. McHale
David R. McHale
Executive Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

/s/

Date: August 5, 2011 By David R. McHale
David R. McHale
Executive Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
(Registrant)

/s/

Date: August 5, 2011

By David R. McHale
David R. McHale
Executive Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
(Registrant)

		/s/
Date: August 5, 2011	By	David R. McHale
		David R. McHale
		Executive Vice President and Chief Financial Officer
		(for the Registrant and as Principal Financial Officer)