NORTHEAST UTILITIES
Form 10-Q
August 07, 2008

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, 2008

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
Ö	

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

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

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

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 at July 31, 2008

Northeast Utilities Common stock, $5.00 par value	155,560,418 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 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 frequently used abbreviations or acronyms that are found in this report.

NU COMPANIES, SEGMENTS OR INVESTMENTS:

Boulos	E.S. Boulos Company
CL&P	The Connecticut Light and Power Company
Con Edison	Consolidated Edison, Inc.
CRC	CL&P Receivables Corporation
HWP	Holyoke Water Power Company
Mt. Tom	Mt. Tom generating plant
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company and subsidiaries
NU or the company	Northeast Utilities
NU Enterprises	At June 30, 2008, NU Enterprises, Inc. is the parent company of Select Energy, NGS, and Boulos. For further information, see Note 10, "Segment Information," to the condensed consolidated financial statements.
NU parent and other companies	NU parent and other companies is comprised of NU parent, Northeast Utilities Service Company, HWP (since January 1, 2007) and other subsidiaries, including The Rocky River Realty Company and The Quinnehtuk Company (both real estate subsidiaries), Mode 1 Communications, Inc. (telecommunications) and the nonenergy-related subsidiaries of Yankee (Yankee Energy Services Company), Yankee Energy Financial Services Company, and NorConn Properties, Inc.)
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, WMECO, the generation segment of PSNH, a natural gas local distribution company, and Yankee Gas. For further information, see Note 10, "Segment Information," to the condensed consolidated financial statements.
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS:

DPU	Massachusetts Department of Public Utilities (formerly the Massachusetts Department of Telecommunications and Energy (DTE))
DPUC	Connecticut Department of Public Utility Control
FERC	Federal Energy Regulatory Commission
NHPUC	New Hampshire Public Utilities Commission
SEC	Securities and Exchange Commission

OTHER:

AFUDC	Allowance For Funds Used During Construction
CfD	Contract for Differences
CTA	Competitive Transition Assessment
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FMCC	Federally Mandated Congestion Charges
GSC	Generation Service Charge
ISO-NE	New England Independent System Operator or ISO New England, Inc.
KWH	Kilowatt-Hour
KV	Kilovolt
LOC	Letter of Credit
MW	Megawatts
NU 2007 Form 10-K	The Northeast Utilities and Subsidiaries combined 2007 Annual Report on Form 10-K as filed with the SEC
NYMPA	New York Municipal Power Agency
PBOP	Postretirement Benefits Other Than Pensions
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
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SFAS	Statement of Financial Accounting Standards
TCAM	Transmission Cost Adjustment Mechanism
TSO	Transitional Standard Offer
UI	The United Illuminating Company
VAR	Voltage Ampere Reactive

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

TABLE OF CONTENTS

NORTHEAST UTILITIES AND SUBSIDIARIES

1

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 12,128	$ 15,104
Investments in securitizable assets (Note 1E)	-	308,182
Receivables, less provision for uncollectible accounts of $41,863 in 2008 and $25,529 in 2007	584,494	401,283
Unbilled revenues	195,414	101,860
Taxes receivable	75,574	13,850
Fuel, materials and supplies	228,767	210,850
Marketable securities - current	82,488	70,816
Derivative assets - current	177,793	105,517
Prepayments and other	37,028	58,794
	1,393,686	1,286,256
Property, Plant and Equipment:		
Electric utility	8,027,373	7,594,606
Gas utility	1,003,459	977,290
Other	287,391	310,535
	9,318,223	8,882,431
Less: Accumulated depreciation: $2,559,324 for electric and gas utility and $158,305 for other in 2008; $2,483,570 for electric and gas utility and $178,193 for other in 2007	2,717,629	2,661,763
	6,600,594	6,220,668
Construction work in progress	1,121,154	1,009,277

	7,721,748	7,229,945
Deferred Debits and Other Assets:		
Regulatory assets	2,449,551	2,057,083
Goodwill	287,591	287,591
Prepaid pension	219,431	202,512
Marketable securities - long-term	38,625	53,281
Derivative assets - long-term	446,631	298,001
Other	151,989	167,153
	3,593,818	3,065,621
Total Assets	$ 12,709,252	$ 11,581,822

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

2

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 87,000	$ 79,000
Long-term debt - current portion	54,286	154,286
Accounts payable	568,774	598,546
Accrued interest	61,786	56,592
Derivative liabilities - current	35,898	71,601
Other	304,795	246,125
	1,112,539	1,206,150
Rate Reduction Bonds	802,259	917,436
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,109,783	1,067,490
Accumulated deferred investment tax credits	27,108	28,845
Deferred contractual obligations	205,935	222,908
Regulatory liabilities	897,282	851,780
Derivative liabilities - long-term	811,147	208,461
Accrued postretirement benefits	170,641	181,507
Other	426,614	383,611
	3,648,510	2,944,602
Capitalization:		
Long-Term Debt	4,090,288	3,483,599
Preferred Stock of Subsidiary - Non-Redeemable	116,200	116,200

Common Shareholders' Equity:		
Common shares, $5 par value - authorized 225,000,000 shares; 176,160,857 shares issued and 155,523,764 shares outstanding in 2008 and 175,924,694 shares issued and 155,079,770 shares outstanding in 2007	880,804	879,623
Capital surplus, paid in	1,469,588	1,465,946
Deferred contribution plan - employee stock ownership plan	(21,481)	(26,352)
Retained earnings	967,329	946,792
Accumulated other comprehensive income	4,819	9,359
Treasury stock, 19,708,136 shares in 2008 and 19,705,545 shares in 2007	(361,603)	(361,533)
Common Shareholders' Equity	2,939,456	2,913,835
Total Capitalization	7,145,944	6,513,634
Commitments and Contingencies (Note 5)		
Total Liabilities and Capitalization	$ 12,709,252	$ 11,581,822

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 1,325,345	$ 1,391,772	$ 2,845,312	$ 3,095,290
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	661,699	804,802	1,485,016	1,875,288
Other	237,203	245,879	523,084	483,112
Maintenance	70,896	59,842	127,605	105,827
Depreciation	68,321	63,420	136,075	126,889
Amortization of regulatory assets/(liabilities), net	41,945	(3,453)	70,800	2,770
Amortization of rate reduction bonds	47,884	47,114	101,234	98,913
Taxes other than income taxes	59,278	57,360	131,107	129,950
Total operating expenses	1,187,226	1,274,964	2,574,921	2,822,749
Operating Income	138,119	116,808	270,391	272,541
Interest Expense:				
Interest on long-term debt	46,449	40,234	89,222	76,447
Interest on rate reduction bonds	12,987	15,839	26,703	32,189
Other interest	6,624	3,504	12,776	10,223
Interest expense, net	66,060	59,577	128,701	118,859
Other Income, Net	10,370	11,873	23,928	25,942
Income from Continuing Operations Before				

Income Tax Expense	82,429	69,104	165,618	179,624
Income Tax Expense	23,192	21,703	46,598	54,426
Income from Continuing Operations Before				
Preferred Dividends of Subsidiary	59,237	47,401	119,020	125,198
Preferred Dividends of Subsidiary	1,389	1,389	2,779	2,779
Income from Continuing Operations	57,848	46,012	116,241	122,419
Discontinued Operations:				
Income from Discontinued Operations	-	564	-	248
Gains from Sale/Disposition of Discontinued Operations	-	3,925	-	2,017
Income Tax Expense	-	1,948	-	1,037
Income from Discontinued Operations	-	2,541	-	1,228
Net Income	$ 57,848	$ 48,553	$ 116,241	$ 123,647
Basic and Fully Diluted Earnings Per Common Share:				
Income from Continuing Operations	$ 0.37	$ 0.30	$ 0.75	$ 0.79
Income from Discontinued Operations	-	0.01	-	0.01
Basic and Fully Diluted Earnings Per Common Share	$ 0.37	$ 0.31	$ 0.75	$ 0.80
Basic Common Shares Outstanding (weighted average)	155,476,492	154,729,676	155,381,302	154,539,678
Fully Diluted Common Shares Outstanding (weighted average)	155,895,348	155,213,094	155,808,481	155,102,672

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS
OF CASH FLOWS

(Unaudited)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 116,241	$ 123,647
Adjustments to reconcile to net cash flows provided by/(used in) operating activities:		
Bad debt expense	13,163	12,917
Depreciation	136,075	126,889
Deferred income taxes	52,995	(10,158)
Pension expense, net of capitalized portion	4,011	10,388
(Deferral)/amortization of recoverable energy costs	(6,046)	6,248
Amortization of rate reduction bonds	101,234	98,913
Amortization of regulatory assets, net	70,800	2,770
Regulatory (refunds and underrecoveries)/overrecoveries	(128,830)	64,174
Derivative assets and liabilities	(25,216)	(36,830)
Deferred contractual obligations	(16,973)	(23,489)
Other non-cash adjustments	(7,165)	(2,989)
Other sources of cash	274	-
Other uses of cash	(15,552)	(35,019)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	35,760	56,248
Fuel, materials and supplies	(17,946)	(12,135)
Investments in securitizable assets	(25,787)	17,674
Other current assets	6,426	7,177
Accounts payable	(20,648)	(67,312)
Counterparty deposits and margin special deposits	59,110	18,926
Taxes receivable/accrued	(31,412)	(372,867)
Other current liabilities	(21,489)	(22,672)

Net cash flows provided by/(used in) operating activities	279,025	(37,500)
Investing Activities:		
Investments in property and plant	(625,133)	(491,137)
Proceeds from sales of investment securities	128,778	101,113
Purchases of investment securities	(130,105)	(103,902)
Rate reduction bond escrow and other deposits	9,010	8,567
Other investing activities	2,385	42
Net cash flows used in investing activities	(615,065)	(485,317)
Financing Activities:		
Issuance of common shares	4,562	8,520
Issuance of long-term debt	660,000	345,000
Retirements of rate reduction bonds	(115,177)	(109,755)
Increase in short-term debt	8,000	-
Retirements of long-term debt	(154,286)	(4,877)
Cash dividends on common shares	(62,574)	(58,502)
Other financing activities	(7,461)	(657)
Net cash flows provided by financing activities	333,064	179,729
Net decrease in cash and cash equivalents	(2,976)	(343,088)
Cash and cash equivalents - beginning of period	15,104	481,911
Cash and cash equivalents - end of period	$ 12,128	$ 138,823

The accompanying notes are an integral part of these 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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (All Companies)

A.

Presentation

Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). The accompanying unaudited condensed consolidated financial statements should be read in conjunction with the entirety of this Quarterly Report on Form 10-Q, the first quarter 2008 Quarterly Report on Form 10-Q and the Annual Reports of Northeast Utilities (NU or the company), The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), and Western Massachusetts Electric Company (WMECO), which were filed with the SEC as part of the Northeast Utilities and subsidiaries combined 2007 Annual Report on Form 10-K (NU 2007 Form 10-K). The accompanying 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 position at June 30, 2008 and December 31, 2007, the results of operations for the three and six months ended June 30, 2008 and 2007 and cash flows for the six months ended June 30, 2008 and 2007. The results of operations and cash flows for the six months ended June 30, 2008 and 2007 are not necessarily indicative of the results expected for a full year.

The condensed consolidated financial statements of NU and its subsidiaries, as applicable, include the accounts of all their respective subsidiaries. Intercompany transactions have been eliminated in consolidation.

The preparation of condensed consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Certain reclassifications of prior period data included in the accompanying condensed consolidated financial statements have been made to conform with the current period's presentation.

NU's condensed consolidated statements of income for the three and six months ended June 30, 2007 classify activity related to the following subsidiaries as discontinued operations:

.

Northeast Generation Company (NGC),

.

The Mt. Tom generating plant (Mt. Tom) previously owned by Holyoke Water Power Company (HWP), and

.

Select Energy Contracting, Inc. (including Reeds Ferry Supply Co., Inc.) (SECI).

For the three and six months ended June 30, 2007, portions of SECI that were included in continuing operations have been reclassified to discontinued operations in the condensed consolidated statements of income as a result of winding down SECI operations in 2007. The amounts of these reclassifications are as follows:

(Millions of Dollars)	**Three Months Ended June 30, 2007**	**Six Months Ended June 30, 2007**
Operating revenues	$ 0.3	$ 1.1
Operating benefits/(expenses)	0.2	(0.9)
Income from discontinued operations	0.5	0.2

Income tax expense from discontinued operations	(0.4)	(0.2)
Net income from discontinued operations	0.1	-

For further information regarding discontinued operations, see Note 7, "Discontinued Operations," to the condensed consolidated financial statements.

B.

Regulatory Accounting

The accounting policies of the regulated companies conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation."

The transmission and distribution segments of CL&P, PSNH and WMECO, along with PSNH's generation segment and Yankee Gas Service Company's (Yankee Gas) distribution segment, continue to be cost-of-service, rate regulated. Management believes that the application of SFAS No. 71 to those segments continues to be appropriate. Management also believes it is probable that NU's regulated companies will recover their investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning an equity return, except for securitized regulatory assets and the majority of deferred benefit costs, which are not supported by equity. Amortization and deferrals of regulatory assets/(liabilities) are included on a net basis in amortization expense on the accompanying condensed consolidated statements of income.

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

	At June 30, 2008				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Securitized assets	$ 793.6	$ 464.3	$ 250.5	$ 78.8	$ -
Income taxes, net	351.3	298.0	10.1	34.1	9.1
Deferred benefit costs	171.7	60.9	45.6	6.3	58.9
Unrecovered contractual obligations	179.1	140.2	-	38.9	-
Regulatory assets offsetting regulated company derivative liabilities	629.2	629.1	-	-	0.1
CL&P CTA and SBC undercollections	50.2	50.2	-	-	-
Other regulatory assets	274.5	135.7	67.9	15.8	55.1
Totals	$ 2,449.6	$ 1,778.4	$ 374.1	$ 173.9	$ 123.2

	At December 31, 2007				
(Millions of Dollars)	NU Consolidated	CL&P	PSNH	WMECO	Yankee Gas and Other
Securitized assets	$ 907.0	$ 548.2	$ 273.2	$ 85.6	$ -
Income taxes, net	335.5	279.4	10.3	38.2	7.6
Deferred benefit costs	201.4	72.2	50.4	8.2	70.6
Unrecovered contractual obligations	189.9	148.0	-	42.0	(0.1)
Regulatory assets offsetting regulated company derivative liabilities	122.3	119.8	2.5	-	-
CL&P CTA and SBC undercollections	90.6	90.6	-	-	-
Other regulatory assets	210.4	71.8	65.0	19.9	53.7
Totals	$ 2,057.1	$ 1,330.0	$ 401.4	$ 193.9	$ 131.8

For information regarding regulatory assets offsetting regulated company derivative liabilities, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Included in NU's other regulatory assets are the regulatory assets associated with the implementation of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $43 million at June 30, 2008 and $40.6 million at December 31, 2007. Management believes that recovery of these regulatory assets is probable.

Additionally, the regulated companies had $2.8 million and $11.9 million of regulatory costs at June 30, 2008 and December 31, 2007, respectively, that were included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets. These amounts represent regulatory costs that have not yet been approved for recovery by the applicable regulatory agency. Management believes these costs are recoverable in future cost-of-service regulated rates.

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

	At June 30, 2008				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas**
Cost of removal	$ 237.1	$ 97.3	$ 67.7	$ 20.8	$ 51.3
Regulatory liabilities offsetting regulated company derivative assets	478.6	384.2	92.7	-	1.7
CL&P GSC and FMCC overcollections	45.1	45.1	-	-	-
Other regulatory liabilities	136.5	73.2	25.0	15.6	22.7
Totals	$ 897.3	$ 599.8	$ 185.4	$ 36.4	$ 75.7

	At December 31, 2007				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas**
Cost of removal	$ 262.6	$ 116.6	$ 72.8	$ 21.5	$ 51.7
Regulatory liabilities offsetting regulated company derivative assets	330.4	313.0	17.2	-	0.2
CL&P GSC and FMCC overcollections	119.2	119.2	-	-	-
Other regulatory liabilities	139.6	52.7	37.6	17.9	31.4
Totals	$ 851.8	$ 601.5	$ 127.6	$ 39.4	$ 83.3

For information regarding regulatory liabilities offsetting regulated company derivative assets, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

C.

Fair Value Measurements

On January 1, 2008, the company adopted SFAS No. 157, "Fair Value Measurements," which establishes a framework for defining and measuring fair value and requires expanded disclosures about fair value measurements. SFAS No. 157:

.

Defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price).

.

Establishes a three-level fair value hierarchy based upon the observability of inputs to the valuations of assets and liabilities.

.

Requires consideration of the company's own creditworthiness and risk of nonperformance when valuing its liabilities.

.

Requires prospective implementation with adjustments to fair value reflected in earnings, similar to a change in estimate, with exceptions including recognition of previously deferred initial gains or losses described below.

.

Requires recognition in retained earnings of previously deferred initial gains or losses on derivative contracts whose estimated fair values are based on significant unobservable inputs. Recognition of the initial gains or losses was previously prohibited under Emerging Issues Task Force Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." CL&P s initial gains and losses on its contracts for differences (CfDs) that would have been recorded in retained earnings upon adoption were recorded as regulatory assets and liabilities because their costs or benefits are expected to be fully recovered from or refunded to customers.

The company applied SFAS No. 157 to the regulated and unregulated companies' derivative contracts that are recorded at fair value and to the marketable securities held in NU's Rabbi Trust and WMECO's prior spent nuclear fuel trust. SFAS No. 157 also applies to investment valuations for NU s pension and other postretirement benefit plans beginning as of December 31, 2008, and beginning in 2009, to nonrecurring fair value measurements of non-financial assets and liabilities such as goodwill and asset retirement obligations.

As a result of adopting SFAS No. 157, the company recorded a pre-tax charge to earnings of $6.1 million as of January 1, 2008 related to derivative liabilities for its remaining unregulated wholesale marketing contracts. For the three and six months ended June 30, 2008, the company recorded a $1 million and $2.2 million pre-tax benefit, respectively, to partially reverse the exit price impact recorded under SFAS No. 157 as the company served out rather than exited the contracts.

The company also recorded changes in fair value of certain derivative contracts of CL&P. Because CL&P is a cost-of-service, rate regulated entity, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers and an offsetting regulatory asset or liability was recorded to reflect these changes. As of January 1, 2008, implementing SFAS No. 157

resulted in a total increase to CL&P's derivative liabilities, with an offset to regulatory assets, of approximately $590 million, and a total decrease to derivative assets, with an offset to regulatory liabilities, of approximately $30 million.

Fair Value Hierarchy: As required by SFAS No. 157, in measuring fair value the company uses observable market data when available and minimizes the use of unobservable inputs. Unobservable inputs are needed to value certain derivative contracts due to complexities in contractual terms and the long duration of a contract. SFAS No. 157 requires inputs used in fair value measurements to be categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement.

The three levels of the fair value hierarchy are described below:

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

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

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

Determination of Fair Value: The following is a description of the valuation techniques utilized in our fair value measurements:

Derivative contracts: Many of the company's derivative positions that are recorded at fair value are classified as Level 3 within the fair value hierarchy and are valued using models that incorporate both observable and unobservable inputs. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs utilized in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under full requirements and supplemental sales contracts, and market volatilities. Discounted cash flow valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect nonperformance risk, including credit. The derivative contracts classified as Level 3 include NU Enterprises, Inc.'s (NU Enterprises) remaining wholesale marketing contract and its related supply contracts, CL&P's CfDs, CL&P's contracts with certain independent power producers (IPPs) and regulated company options and financial transmission rights (FTRs).

Other derivative contracts recorded at fair value are classified as Level 2 within the fair value hierarchy. An active market for the same or similar contracts exists for these contracts, which include regulated company forward contracts to purchase energy and interest rate swap agreements for the regulated companies and NU parent. For these contracts, valuations are based on quoted prices in the market and include some modeling using market-based assumptions.

For further information on derivative contracts, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Marketable securities: The company holds in trust marketable securities, which include equity securities, mutual funds and cash equivalents, and fixed maturity securities.

Equity securities, mutual funds and cash equivalents are classified as Level 1 in the fair value hierarchy. These investments are traded in active markets and quoted prices are available for identical investments.

Fixed maturity securities classified as Level 2 within the fair value hierarchy include U.S. Treasury securities, corporate bonds, collateralized mortgage obligations, U.S. pass-through bonds, asset-backed securities, commercial mortgage-backed securities, and commercial paper. The fair value of these instruments is estimated using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures.

For further information see Note 3, "Fair Value Measurements," to the accompanying condensed consolidated financial statements.

D.

Allowance for Funds Used During Construction

The 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 on the accompanying condensed consolidated statements of income:

	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars, except percentages)	**June 30, 2008**	**June 30, 2007**	**June 30, 2008**	**June 30, 2007**
Borrowed funds	$ 4.4	$ 4.3	$ 9.1	$ 8.6
Equity funds	6.8	4.0	15.1	6.3
Totals	$ 11.2	$ 8.3	$ 24.2	$ 14.9
Average AFUDC rates	7.9%	7.5%	8.1%	7.2%

The regulated companies' average AFUDC rate is based on a Federal Energy Regulatory Commission (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 eligible construction work in progress (CWIP) amounts to calculate AFUDC. Although AFUDC is recorded on 100 percent of CL&P's CWIP for its major transmission projects in southwest Connecticut, 50 percent of this AFUDC is being reserved as a regulatory liability to reflect current rate base recovery for 50 percent of the CWIP as a result of FERC approved transmission incentives.

E.

Sale of Customer Receivables

Prior to June 30, 2008, under the Receivables Purchase and Sale Agreement, CL&P Receivables Corporation (CRC), a consolidated, wholly-owned subsidiary of CL&P, purchased an undivided interest in CL&P's accounts receivable and unbilled revenues and could sell up to $100 million thereof to a financial institution. At December 31, 2007, there were $20 million in such sales. On June 30, 2008, there were no receivables sold under that facility, and CL&P chose to terminate the Receivables Purchase and Sale Agreement.

At December 31, 2007, amounts totaling $308.2 million sold to CRC by CL&P but not sold to the financial institution were included in investments in securitizable assets on the accompanying condensed consolidated balance sheet. These amounts would have been excluded from CL&P's assets in the event of bankruptcy by CL&P. As of June 30, 2008, these amounts were no longer excludable from CL&P's assets in the event of bankruptcy and were no longer securitizable. Since CL&P chose to terminate the Receivables Purchase and Sale Agreement at June 30, 2008, amounts held by CRC were included in accounts receivables and unbilled revenues on the accompanying condensed consolidated balance sheet.

F.

Cash and Cash Equivalents

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

G.

Special Deposits and Counterparty Deposits

To the extent Select Energy, Inc. (Select Energy) requires collateral from counterparties, or the counterparties require collateral from Select Energy, cash held on deposit by Select Energy or with unaffiliated counterparties and brokerage firms as a part of the total collateral required based on Select Energy s position in the transaction. Select Energy's right to use cash collateral is determined by the terms of the related agreements. Key factors affecting the unrestricted status of a portion of this cash collateral include the financial standing of Select Energy and of NU as its credit supporter.

Special deposits paid to unaffiliated counterparties and brokerage firms totaled $18.9 million at December 31, 2007. There were no special deposits as of June 30, 2008. These amounts are recorded as current assets and are included in prepayments and other on the accompanying condensed consolidated balance sheets. Balances collected from counterparties resulting from Select Energy s credit management activities totaled $6.4 million at June 30, 2008. There were no counterparty deposits for Select Energy as of December 31, 2007. These amounts are recorded as current liabilities and are included in other current liabilities on the accompanying condensed consolidated balance sheets.

CL&P and WMECO had $24.8 million and $9 million, respectively, of counterparty deposits at June 30, 2008 related to credit management activities. These amounts were recorded as current liabilities - other on the accompanying condensed consolidated balance sheets. There were no counterparty deposits for these companies as of December 31, 2007.

NU also had amounts on deposit related to special purpose entities used to facilitate the issuance of rate reduction bonds and certificates. These amounts totaled $34.5 million and $43.5 million at June 30, 2008 and December 31, 2007, respectively. These amounts totaled $8.9 million and $14.3 million for CL&P, $21.2 million and $24.4 million for PSNH, and $4.4 million and $4.8 million for WMECO at June 30, 2008 and December 31, 2007, respectively. In addition, the company had $6.5 million and $6.4 million in other cash deposits held with unaffiliated parties at June 30, 2008 and December 31, 2007, respectively, primarily related to CL&P's transmission projects. These amounts were included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets.

H.

Other Income, Net

The pre-tax components of other income/(loss) items are as follows:

NU	**For the Three Months Ended**		**For the Six Months Ended**	
(Millions of Dollars)	**June 30, 2008**	**June 30, 2007**	**June 30, 2008**	**June 30, 2007**
Other Income:				
Investment income	$ 2.0	$ 5.9	$ 3.9	$ 14.4
AFUDC - equity funds	6.8	4.0	15.1	6.3
Energy Independence Act incentives	3.4	2.2	8.9	4.9
Other	0.2	0.4	0.4	0.9
Total Other Income	12.4	12.5	28.3	26.5
Other Loss:				
Investment loss	(1.2)	-	(3.8)	-
Investment write-down	-	(0.5)	-	(0.5)
Other	(0.8)	(0.1)	(0.6)	(0.1)
Total Other Loss	(2.0)	(0.6)	(4.4)	(0.6)
Total Other Income, Net	$ 10.4	$ 11.9	$ 23.9	$ 25.9

CL&P	**For the Three Months Ended**		**For the Six Months Ended**	
(Millions of Dollars)	**June 30, 2008**	**June 30, 2007**	**June 30, 2008**	**June 30, 2007**
Other Income:				
Investment income	$ 1.9	$ 1.6	$ 3.3	$ 3.0
AFUDC - equity funds	5.8	2.9	12.4	4.4
Energy Independence Act incentives	3.4	2.2	8.9	4.9
Other	0.2	0.2	0.3	0.5
Total Other Income	11.3	6.9	24.9	12.8
Other Loss:				
Investment loss	(0.8)	-	(2.6)	-
Other	(0.9)	-	(0.6)	(0.1)
Total Other Loss	(1.7)	-	(3.2)	(0.1)
Total Other Income, Net	$ 9.6	$ 6.9	$ 21.7	$ 12.7

PSNH	**For the Three Months Ended**		**For the Six Months Ended**	
(Millions of Dollars)	**June 30, 2008**	**June 30, 2007**	**June 30, 2008**	**June 30, 2007**
Other Income:				
Investment income	$ 0.6	$ 0.2	$ 0.9	$ 0.4
AFUDC - equity funds	0.9	0.5	2.2	0.9
Other	-	-	0.1	0.1
Total Other Income	1.5	0.7	3.2	1.4
Investment loss	(0.2)	-	(0.6)	-
Total Other Income, Net	$ 1.3	$ 0.7	$ 2.6	$ 1.4

WMECO	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars)	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
Other Income:				
Investment income	$ 0.4	$ 0.3	$ 0.6	$ 0.6
AFUDC - equity funds	0.2	-	0.4	-
Conservation and load management incentive	0.1	0.1	0.2	0.3
Total Other Income	0.7	0.4	1.2	0.9
Investment loss	(0.2)	-	(0.5)	-
Total Other Income, Net	$ 0.5	$ 0.4	$ 0.7	$ 0.9

Investment income for NU includes equity in earnings of regional nuclear generating and transmission companies of $0.3 million and $0.4 million for the three months ended June 30, 2008 and 2007, respectively, and $1 million and $1.1 million for the six months ended June 30, 2008 and 2007, respectively. Equity in earnings relates to the company's investment in Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company, Yankee Atomic Electric Company and two regional transmission companies.

I.

Income Taxes

Tax Positions: NU is currently working to resolve all open tax years. It is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. NU has significantly advanced settlement positions with the Internal Revenue Service related to the timing of deducting expenses. These settlement positions involve the 2002-2004 tax years, and if finally agreed upon, would result in a decrease in unrecognized tax benefits in the range of $20 million to $22 million, of which the tax impact on earnings is not expected to be material. These ranges are $7 million to $8 million for CL&P, $9 million to $10 million for PSNH and $2 million to $3 million for WMECO.

J.

Other Taxes

Certain excise taxes levied by state or local governments are collected by NU from its customers. These excise taxes are accounted for on a gross basis with collections in revenues and payments in expenses. For the three and six months ended June 30, 2008, gross receipts taxes, franchise taxes and other excise taxes of $27.4 million and $58.4 million, respectively, were included in operating revenues and taxes other than income taxes on the accompanying condensed consolidated statements of income. For the three and six months ended June 30, 2007, these amounts totaled $26.3 million and $58 million, respectively. Certain sales taxes are also collected by the regulated companies from their customers as agents for state and local governments and are recorded on a net basis with no impact on the accompanying condensed consolidated statements of income.

2.

DERIVATIVE INSTRUMENTS (NU, Select Energy, CL&P, PSNH, Yankee Gas)

Contracts that are derivatives and do not meet the requirements to be treated as a cash flow hedge or normal purchase or normal sale are recorded at fair value with changes in fair value included in earnings. For those contracts that meet the definition of a derivative and meet the cash flow hedge requirements, including those related to initial and ongoing documentation, the contract is recorded at fair value and the changes in the fair value of the effective portion of those contracts are recognized in accumulated other comprehensive income. Cash flow hedges include forward interest rate swap agreements on proposed debt issuances. When a cash flow hedge is settled, the settlement amount is recorded in accumulated other comprehensive income and is amortized into earnings over the term of the debt. Cash flow hedges impact net income when the hedged items affect earnings, when hedge ineffectiveness is measured and recorded, or when the forecasted transaction being hedged is improbable of occurring. Derivative contracts designated as fair value hedges and the items they are hedging are both recorded at fair value with changes in fair value of both items recognized in earnings. Derivative contracts that meet the requirements of a normal purchase or sale, and are so designated, are recognized in revenues or expenses, as applicable, when the quantity of the contract is delivered.

The fair value of the company's derivative contracts may not represent amounts that will be realized. For further information on the fair value of derivative contracts, see Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 3, "Fair Value Measurements," to the condensed consolidated financial statements. On the accompanying condensed consolidated balance sheets at June 30, 2008 and December 31, 2007, these amounts are recorded as current or long-term derivative assets or liabilities and are summarized as follows:

	At June 30, 2008				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises - Wholesale	$ 22.1	$ 22.5	$ (33.7)	$ (85.5)	$ (74.6)
Regulated Companies - Gas:					
Supply	0.1	1.6	(0.1)	-	1.6
Interest Rate Hedging	0.8	-	-	-	0.8
Regulated Companies - Electric:					
Supply/Stranded Costs	154.8	420.7	(2.1)	(725.6)	(152.2)
NU Parent:					
Interest Rate Hedging	-	1.8	-	-	1.8
Totals	$ 177.8	$ 446.6	$ (35.9)	$ (811.1)	$ (222.6)

	At December 31, 2007				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises - Wholesale	$ 36.2	$ 7.2	$ (64.9)	$ (72.5)	$ (94.0)
Regulated Companies - Gas:					
Supply	0.2	-	-	-	0.2
Interest Rate Hedging	0.9	-	-	-	0.9
Regulated Companies - Electric:					
Supply/Stranded Costs	59.8	290.8	(6.7)	(136.0)	207.9
Interest Rate Hedging	3.3	-	-	-	3.3
NU Parent:					
Interest Rate Hedging	5.1	-	-	-	5.1
Totals	$ 105.5	$ 298.0	$ (71.6)	$ (208.5)	$ 123.4

For the regulated companies, except for existing interest rate swap agreements, offsetting regulatory assets or liabilities are recorded for the changes in fair value of their contracts, as these contracts were part of the stranded costs or are current regulated operating costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates.

The business activities of NU Enterprises that result in the recognition of derivative assets also result in exposures to credit risk of energy marketing and trading counterparties. At June 30, 2008, Select Energy had $44.6 million of derivative assets from wholesale activities that are exposed to counterparty credit risk, a significant portion of which is contracted with several creditworthy and rated public entities.

NU Enterprises - Wholesale: Certain electric derivative contracts are part of NU Enterprises' remaining wholesale marketing business. These contracts include short-term and long-term electric supply contracts and a contract to sell electricity to the New York Municipal Power Agency (NYMPA) (an agency that is comprised of municipalities) that expires in 2013. The fair value of the contracts was determined using prices from external sources through 2011 for on-peak and off-peak periods and through 2012 for on-peak periods, except for one contract, under which a portion of the fair value is also determined from a model based on natural gas prices and a heat-rate conversion factor to electricity for off-peak periods in 2012 and for all periods in 2013. The 2007 balances also included a full requirements contract and the related short-term supply contracts to sell electricity to a utility. These contracts expired on May 31, 2008.

Regulated Companies - Gas - Supply: Yankee Gas's supply derivatives consist of peaking supply arrangements to serve winter load obligations and firm retail sales contracts with options to curtail delivery. These contracts are subject to fair value accounting as these contracts are derivatives that cannot be designated as normal purchases and sales because of the optionality in the contract terms. An offsetting regulatory liability/asset was recorded for these amounts as management believes that these costs will be refunded or recovered in rates.

Regulated Companies - Gas - Interest Rate Hedging: Yankee Gas has a forward interest rate swap agreement to hedge the interest cash outflows associated with its planned $100 million debt issuance in September 2008. The interest rate swap is based on a 10-year LIBOR swap rate and matches the index used for the debt issuance. As a cash flow hedge, the fair value of the hedge is recorded as a derivative liability and derivative asset on the accompanying condensed consolidated balance sheets as of June 30, 2008 and December 31, 2007, respectively, with an offsetting amount, net of tax, included in accumulated other comprehensive income.

Regulated Companies - Electric - Supply/Stranded Costs: CL&P has contracts with two IPPs to purchase power that contain pricing provisions that are not clearly and closely related to the price of power and therefore do not qualify for the normal purchases and sales exception. The fair values of these derivatives at June 30, 2008 included a derivative asset with a fair value of $381 million and a derivative liability with a fair value of $38.2 million. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of stranded costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates. At December 31, 2007, the fair values of these derivatives included a derivative asset with a fair value of $311.2 million and a derivative liability with a fair value of $31.8 million.

CL&P has entered into FTR contracts and bilateral basis swaps to limit the congestion costs associated with its standard offer contracts. An offsetting regulatory asset or liability has been recorded as management believes that these costs will be recovered or refunded in rates. At June 30, 2008, the fair value of these contracts was recorded as a derivative asset of $3.2 million on the accompanying condensed consolidated balance sheets. At December 31, 2007, the fair value of these contracts was recorded as a derivative asset of $1.4 million and a derivative liability of $1.3 million on the accompanying condensed consolidated balance sheets.

Pursuant to Public Act 05-01, "An Act Concerning Energy Independence," in August 2007, the Connecticut Department of Public Utility Control (DPUC) approved two CL&P contracts associated with the capacity of two generating projects to be built or modified. The DPUC also approved two capacity-related contracts entered into by The United Illuminating Company (UI), one with a generating project to be built and one with a new demand response project. The total capacity of these four projects is expected to be approximately 787 megawatts (MW). The contracts, referred to as CfDs, obligate the utilities' customers to pay the difference between a set capacity price and the forward capacity market price that the projects receive in the New England Independent System Operator (ISO-NE) capacity markets for periods of up to 15 years beginning in 2009. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs, with 80 percent to CL&P and 20 percent to UI. The ultimate cost to CL&P under the contracts will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. At June 30, 2008, the fair value of the CL&P CfDs was recorded as a derivative liability of $689.5 million. The fair values of UI's share of the CL&P's contracts and CL&P's share of UI's contracts were recorded as a derivative asset of $98.6 million. An offsetting regulatory asset of $590.9 million was recorded, as management believes these amounts will be recovered from or refunded to customers in cost-of-service, regulated rates. The value of CL&P's CfDs at June 30, 2008 included approximately $100 million of initial gains and losses, previously deferred due to the use of significant unobservable inputs in the valuation, that were recorded upon adoption of SFAS No. 157 on January 1, 2008. At December 31, 2007, changes in CfD fair values since inception were recorded as a derivative liability of $107.1 million, and UI's share and one CL&P CfD were recorded as derivative assets of $20.8 million. Offsetting regulatory assets of $86.7 million and regulatory liabilities of $0.4 million were also recorded at December 31, 2007. A 2007 NRG Energy, Inc. (NRG) appeal of the DPUC's decision selecting the CfDs was taken into consideration in valuing the CfDs as of December 31, 2007, reducing the net negative derivative values by approximately $215 million. In February 2008, the appeal was denied, which increased derivative liabilities in 2008.

PSNH has electricity procurement contracts that are derivatives. The fair values of these contracts are calculated based on market prices and were recorded as derivative assets totaling $51.8 million at June 30, 2008. At December 31, 2007, the fair value was recorded as a derivative asset of $1.5 million and a derivative liability of $2.5 million. An offsetting regulatory liability/asset was recorded as management believes that these costs will be refunded or recovered in rates as the energy is delivered.

PSNH has a contract to assign its transmission rights in a direct current transmission line in exchange for two energy call options which expire in 2010. These energy call options are derivatives that do not qualify for the normal purchases and sales exception and are accounted for at fair value based on market prices. At June 30, 2008 and December 31, 2007, the options were recorded as a derivative asset of $40.9 million and $15.7 million, respectively. An offsetting regulatory liability was recorded, as the benefit of this arrangement will be refunded to customers in rates.

Regulated Companies - Electric - Interest Rate Hedging: At December 31, 2007, CL&P had two forward interest rate swap agreements to hedge the interest cash outflows associated with its debt issuance of $300 million in May 2008. PSNH had a forward interest rate swap agreement to hedge the interest cash outflows associated with its debt issuance of $110 million in May 2008. Prior to termination in May 2008, the interest rate swaps were based on a 10-year LIBOR swap rate and matched the index used for the debt issuances. As cash flow hedges, the fair values of these hedges were recorded as derivative assets at December 31, 2007 on the accompanying condensed consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

NU Parent - Interest Rate Hedging: In March 2003, to manage the interest rate characteristics of the company's long-term debt, NU parent entered into a fixed to floating interest rate swap on its $263 million, 7.25 percent fixed rate senior notes that mature on April 1, 2012. Under fair value hedge accounting, the changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in interest expense, which generally offset each other in the condensed consolidated statements of income. The cumulative change in the fair value of the swap and the long-term debt was recorded as a derivative asset and an increase to long-term debt of $1.8 million and $4.2 million at June 30, 2008 and December 31, 2007, respectively.

NU parent had a forward interest rate swap agreement to hedge the interest cash outflows associated with its planned debt issuance in June 2008. Prior to termination in June 2008, the interest rate swap was based on a 5-year LIBOR swap rate and a notional amount of $200 million, and matched the index used for the debt issuance. As a cash flow hedge at December 31, 2007, the fair value of the hedge was recorded as a $0.9 million derivative asset on the accompanying condensed consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

3.

FAIR VALUE MEASUREMENTS (All Companies)

Items Measured at Fair Value on a Recurring Basis: The company's assets and liabilities recorded at fair value on a recurring basis have been categorized based upon the fair value hierarchy in accordance with SFAS No. 157. See Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," for further information regarding the hierarchy and fair value measurements.

The following table presents the amounts of assets and liabilities carried at fair value at June 30, 2008 by the level in which they are classified within the SFAS No. 157 valuation hierarchy:

(Millions of Dollars)	**Total NU**	**CL&P**	**PSNH**	**WMECO**	**NU Enterprises**	**Yankee Gas**	**NU Parent**
Derivative Assets:							
Level 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Level 2	54.4	-	51.8	-	-	0.8	1.8
Level 3	570.0	482.8	40.9	-	44.6	1.7	-
Total	$ 624.4	$ 482.8	$ 92.7	$ -	$ 44.6	$ 2.5	$ 1.8
Derivative Liabilities:							
Level 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Level 2	-	-	-	-	-	-	-
Level 3	(847.0)	(727.7)	-	-	(119.2)	(0.1)	-
Total	$ (847.0)	$ (727.7)	$ -	$ -	$ (119.2)	$ (0.1)	$ -

Marketable Securities:							
Level 1	$ 43.5	$ -	$ -	$ 6.6	$ -	$ -	$ 36.9
Level 2	77.6	-	-	50.1	-	-	27.5
Level 3	-	-	-	-	-	-	-
Total	$ 121.1	$ -	$ -	$ 56.7	$ -	$ -	$ 64.4

The following tables present changes for the three and six months ended June 30, 2008 in the Level 3 category of assets and liabilities measured at fair value on a recurring basis. This category includes derivative assets and liabilities, which are presented net. The derivative amounts at January 1, 2008 reflect the fair values after initial adoption of SFAS No. 157. 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, 2008.

	For the Three Months Ended June 30, 2008				
(Millions of Dollars)	**Total NU**	**CL&P**	**PSNH**	**NU Enterprises**	**Yankee Gas**
Derivatives, Net:					
Fair value at March 31, 2008	$ (488.5)	$ (430.3)	$ 22.8	$ (81.1)	$ 0.1
Net realized/unrealized gains included in:					
Earnings (1)	1.2	-	-	1.2	-
Regulatory assets/liabilities	228.7	209.1	18.1	-	1.5
Purchases, issuances and settlements	(18.4)	(23.7)	-	5.3	-
Fair value at June 30, 2008	$ (277.0)	$ (244.9)	$ 40.9	$ (74.6)	$ 1.6
Quarterly change in unrealized losses included in earnings relating to items held at June 30, 2008	$ (2.3)	$ -	$ -	$ (2.3)	$ -

	For the Six Months Ended June 30, 2008				
(Millions of Dollars)	**Total NU**	**CL&P**	**PSNH**	**NU Enterprises**	**Yankee Gas**
Derivatives, Net:					
Fair value at January 1, 2008 [2]	$ (511.1)	$ (426.9)	$ 15.7	$ (100.1)	$ 0.2
Net realized/unrealized gains included in:					
Earnings [1]	4.8	-	-	4.8	-
Regulatory assets/liabilities	245.5	218.9	25.2	-	1.4
Purchases, issuances and settlements	(16.2)	(36.9)	-	20.7	-
Fair value at June 30, 2008	$ (277.0)	$ (244.9)	$ 40.9	$ (74.6)	$ 1.6
Period change in unrealized losses included in earnings relating to items held at June 30, 2008	$ (1.5)	$ -	$ -	$ (1.5)	$ -

(1)

Realized and unrealized gains and losses on derivatives included in earnings relate to the remaining Select Energy wholesale marketing contracts and are reported in fuel, purchased and net interchange power on the accompanying condensed consolidated statements of income.

(2)

Amounts as of January 1, 2008 reflect fair values after initial adoption of SFAS No. 157. As a result of implementing SFAS No. 157, the company recorded an increase to derivative liabilities and a pre-tax charge to earnings of $6.1 million as of January 1, 2008 related to NU Enterprises' remaining derivative contracts. The company also recorded changes in fair value of CL&P's CfD and IPP contracts, resulting in increases to CL&P's derivative liabilities of approximately $590 million, with an offset to regulatory assets and a decrease to CL&P's derivative assets of approximately $30 million with an offset to regulatory liabilities.

4.

PENSION BENEFITS AND POSTRETIREMENT BENEFITS OTHER THAN PENSIONS (All Companies)

NU's subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all regular NU employees and also provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees (post-retirement benefits other than pension (PBOP) Plan). In addition, NU maintains a Supplemental Executive Retirement Plan (SERP) which provides benefits to eligible participants, who are officers of NU, that would have been provided to them under the Pension Plan if certain Internal Revenue Code and other limitations were not imposed.

The components of net periodic expense/(income) for the Pension Plan, PBOP Plan and SERP for the three and six months ended June 30, 2008 and 2007 are as follows:

NU	**For the Three Months Ended June 30,**					
	Pension Benefits		**Postretirement Benefits**		**SERP Benefits**	
(Millions of Dollars)	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Service cost	$ 11.1	$ 12.5	$ 1.8	$ 2.1	$ 0.2	**$** 0.2
Interest cost	35.9	35.5	7.0	6.6	0.5	0.5
Expected return on plan assets	(50.0)	(51.2)	(5.3)	(4.5)	-	-
Amortization of unrecognized net transition obligation	-	0.1	2.9	2.9	-	0.2
Amortization of prior service cost	2.5	2.3	(0.1)	(0.1)	-	-
Amortization of actuarial loss	1.1	5.0	2.7	2.9	0.1	-
Net periodic expense	$ 0.6	$ 4.2	$ 9.0	$ 9.9	$ 0.8	$ 0.9

NU	**For the Six Months Ended June 30,**					
	Pension Benefits		**Postretirement Benefits**		**SERP Benefits**	
(Millions of Dollars)	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Service cost	$ 21.8	$ 24.3	$ 3.6	$ 4.2	$ 0.3	**$** 0.4
Interest cost	72.1	69.1	14.1	13.3	1.0	1.0
Expected return on plan assets	(100.1)	(98.4)	(10.5)	(9.1)	-	-
Amortization of unrecognized net transition obligation	0.1	0.1	5.8	5.8	-	-
Amortization of prior service cost	4.9	3.9	(0.2)	(0.1)	0.1	0.3
Amortization of actuarial loss	2.5	11.8	5.3	5.8	0.1	0.1
Net periodic expense	$ 1.3	$ 10.8	$ 18.1	$ 19.9	$ 1.5	$ 1.8

A portion of these pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were approximately $1.3 million and $2.7 million for the three and six months ended June 30, 2008, respectively, and $(0.2) million and $0.4 million for the three and six months ended June 30, 2007, respectively. The amounts for the three and six months ended June 30, 2008 offset capital costs, as pension income was recorded for certain of NU s subsidiaries.

CL&P	**For the Three Months Ended June 30,**					
	Pension Benefits		**Postretirement Benefits**		**SERP Benefits**	
(Millions of Dollars)	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Service cost	$ 3.9	$ 4.5	$ 0.6	$ 0.7	$ -	$ -
Interest cost	12.8	12.4	2.8	2.6	0.1	0.1
Expected return on plan assets	(23.4)	(23.6)	(2.1)	(1.8)	-	-
Amortization of unrecognized net transition obligation	-	-	1.5	1.6	-	-
Amortization of prior service cost	1.1	1.0	-	-	-	-
Amortization of actuarial loss	0.3	1.4	1.1	1.1	-	-
Net periodic (income)/expense	$ (5.3)	$ (4.3)	$ 3.9	$ 4.2	$ 0.1	$ 0.1

CL&P	**For the Six Months Ended June 30,**					
	Pension Benefits		**Postretirement Benefits**		**SERP Benefits**	
(Millions of Dollars)	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Service cost	$ 7.6	$ 8.4	$ 1.1	$ 1.4	$ -	$ -
Interest cost	25.7	24.7	5.7	5.3	0.1	0.1
Expected return on plan assets	(46.7)	(45.7)	(4.2)	(3.6)	-	-
Amortization of unrecognized net transition obligation	-	-	3.1	3.1	-	-
Amortization of prior service cost	2.1	1.7	-	-	-	-
Amortization of actuarial loss	0.6	3.9	2.2	2.2	0.1	0.1
Net periodic (income)/expense	$ (10.7)	$ (7.0)	$ 7.9	$ 8.4	$ 0.2	$ 0.2

Not included in the pension income amounts above are related intercompany allocations totaling $1.9 million and $4 million for the three and six months ended June 30, 2008, respectively, and $2.9 million and $6 million for the three and six months ended June 30, 2007, respectively. Excluded from postretirement benefits are related intercompany allocations of $1.7 million and $3.4 million for the three and six months ended June 30, 2008, respectively, and $1.8 million and $3.6 million for the three and six months ended June 30, 2007, respectively. Excluded from SERP expenses are related intercompany allocations of $0.4 million and $0.8 million for the three and six months ended June 30, 2008, respectively, and $0.5 million and $1.0 million for the three and six months ended June 30, 2007, respectively.

For CL&P, a portion of the pension amounts, including intercompany allocations, is capitalized related to current employees that are working on capital projects. Amounts capitalized were $2.2 million and $4.4 million for the three and six months ended June 30, 2008, respectively, and $1.3 million and $1.9 million for the three and six months ended June 30, 2007, respectively. These amounts offset capital costs, as pension income was recorded for those periods.

PSNH	For the Three Months Ended June 30,					
	Pension Benefits		Postretirement Benefits		SERP Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Service cost	$ 2.3	$ 2.4	$ 0.4	$ 0.5	$ -	$ -
Interest cost	5.8	5.7	1.3	1.2	-	-
Expected return on plan assets	(4.5)	(4.7)	(1.0)	(0.8)	-	-
Amortization of unrecognized net transition obligation	-	0.1	0.6	0.6	-	
Amortization of prior service cost	0.5	0.5	-	-	-	-
Amortization of actuarial loss	0.4	1.0	0.5	0.5	0.1	0.1
Net periodic expense	$ 4.5	$ 5.0	$ 1.8	$ 2.0	$ 0.1	$ 0.1

PSNH	For the Six Months Ended June 30,					
	Pension Benefits		Postretirement Benefits		SERP Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Service cost	$ 4.5	$ 5.0	$ 0.8	$ 0.9	$ -	$ -
Interest cost	11.6	11.0	2.6	2.5	-	0.1
Expected return on plan assets	(9.0)	(9.0)	(2.0)	(1.7)	-	-
Amortization of unrecognized net transition obligation	0.2	0.1	1.2	1.2	-	-
Amortization of prior service cost	0.9	0.8	-	-	-	-
Amortization of actuarial loss	0.8	2.2	0.9	1.1	0.1	0.1
Net periodic expense	$ 9.0	$ 10.1	$ 3.5	$ 4.0	$ 0.1	$ 0.2

Not included in the pension expense amounts above are related intercompany allocations totaling $0.4 million and $0.8 million for the three and six months ended June 30, 2008, respectively, and $0.5 million and $1 million for the three and six months ended June 30, 2007, respectively. Excluded from postretirement benefits are related intercompany allocations of $0.4 million and $0.7 million for the three and six months ended June 30, 2008, respectively, and $0.3 million and $0.6 million for the three and six months ended June 30, 2007, respectively. Excluded from SERP expenses are related intercompany allocations of $0.1 million and $0.2 million for the three and six months ended June 30, 2008 and 2007, respectively.

For PSNH, a portion of these pension amounts, including intercompany allocations, is capitalized related to current employees that are working on capital projects. Amounts capitalized were $1.2 million and $2.3 million for the three and six months ended June 30, 2008, respectively, and $1.2 million and $2.5 million for the three and six months ended June 30, 2007, respectively.

WMECO	**For the Three Months Ended June 30,**				**For the Six Months Ended June 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
	2008	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
(Millions of Dollars)								
Service cost	$ 0.8	$ 1.0	$ 0.1	$ 0.2	$ 1.6	$ 1.7	$ 0.2	$ 0.3
Interest cost	2.6	2.5	0.6	0.6	5.2	5.0	1.2	1.1
Expected return on plan assets	(5.1)	(5.2)	(0.5)	(0.5)	(10.4)	(10.1)	(1.0)	(0.9)
Amortization of unrecognized net transition obligation	-	-	0.4	0.3	-	-	0.7	0.7
Amortization of prior service cost	0.2	0.2	-	-	0.5	0.4	-	-
Amortization of actuarial loss	-	0.2	0.1	0.2	0.1	0.7	0.3	0.4
Net periodic (income)/expense	$ (1.5)	$ (1.3)	$ 0.7	$ 0.8	$ (3.0)	$ (2.3)	$ 1.4	$ 1.6

A de minimis amount of SERP expense was recorded for WMECO for each of the three and six months ended June 30, 2008 and 2007.

Not included in the pension income amounts above are related intercompany allocations totaling $0.4 million and $0.7 million for the three and six months ended June 30, 2008, respectively, and $0.5 million and $1 million for the three and six months ended June 30, 2007, respectively. Excluded from postretirement benefits are related intercompany allocations of $0.3 million and $0.5 million for the three and six months ended June 30, 2008, respectively, and $0.3 million and $0.6 million for the three and six months ended June 30, 2007, respectively.

For WMECO, a portion of these pension amounts, including intercompany allocations, is capitalized related to current employees that are working on capital projects. Amounts capitalized were $0.5 million and $1.1 million for the three and six months ended June 30, 2008, respectively, and $0.5 million and $0.8 million for the three and six months ended June 30, 2007, respectively. These amounts offset capital costs, as pension income was recorded for those periods.

5.

COMMITMENTS AND CONTINGENCIES

A.

Regulatory Developments and Rate Matters (CL&P, PSNH, WMECO, Yankee Gas)

Connecticut:

CTA and SBC Reconciliation: The Competitive Transition Assessment (CTA) allows CL&P to recover stranded costs, such as securitization costs associated with its rate reduction bonds, amortization of regulatory assets, and IPP over-market costs, while the System Benefits Charge (SBC) allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes, and displaced worker protection costs.

On March 31, 2008, CL&P filed with the DPUC its 2007 CTA and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million. This amount was recorded as a decrease to the CTA regulatory asset on the accompanying condensed consolidated balance sheets. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million. This amount was recorded as a regulatory asset on the accompanying condensed consolidated balance sheets. Management expects a decision in this docket from the DPUC by the end of 2008 and does not expect the outcome to have a material adverse impact on CL&P's net income, financial position or cash flows.

Procurement Fee Rate Proceedings: CL&P was allowed to collect a fixed procurement fee of 0.50 mills per kilowatt-hour (KWH) from customers that purchased transitional standard offer (TSO) service from 2004 through the end of 2006. One mill is equal to one tenth of a cent. That fee could increase to 0.75 mills per KWH if CL&P outperforms certain regional benchmarks. CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of the procurement fee and requested approval of $5.8 million in incentive fees. On December 8, 2005, a draft decision was issued in this docket, which accepted the methodology as proposed by CL&P and authorized payment of the pre-tax $5.8 million incentive fee. Subsequent to this draft decision the record was re-opened for numerous inputs. Additional hearings were held on December 10, 2007 and January 30, 2008 and the record was then closed. A date for the new draft decision in this docket has not yet been determined by the DPUC. Management continues to believe that final regulatory approval of the $5.8 million pre-tax amount, which was reflected in 2005 earnings, is probable.

Purchased Gas Adjustment: In 2005 and 2006, the DPUC issued decisions regarding Yankee Gas s Purchased Gas Adjustment (PGA) clause charges and required an audit of previously recovered PGA revenues of approximately $11 million associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund approximately $5.8 million in previous recoveries to its customers. The $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the second quarter 2008 earnings of Yankee Gas.

New Hampshire:

ES and SCRC Reconciliation and Rates: On an annual basis, PSNH files with the New Hampshire Public Utilities Commission (NHPUC) a default energy service charge/stranded cost recovery charge (ES/SCRC) reconciliation filing for the preceding year. The NHPUC reviews the filing, which includes a prudence review of PSNH's generation business segment operations. On May 1, 2008, PSNH filed its 2007 ES/SCRC reconciliation with the NHPUC. On June 27, 2008, the NHPUC issued a procedural schedule, with hearings scheduled in November 2008. Management does not expect the outcome of the NHPUC review to have a material adverse impact on PSNH's net income, financial position or cash flows.

Massachusetts:

Transition Cost Reconciliations: WMECO filed its 2005 transition cost reconciliation with the Massachusetts Department of Public Utilities (DPU) on March 31, 2006 and filed its 2006 transition cost reconciliation with the DPU on March 31, 2007. The DPU opened a proceeding for these filings, and evidentiary hearings were held on August 29, 2007. The briefing process was completed during October 2007. On June 20, 2008, the DPU issued its final decision on these filings, which resulted in a pre-tax charge of $1.6 million to WMECO s condensed consolidated statements of income for the three and six months ended June 30, 2008. The DPU ordered WMECO to use a return on equity of 11 percent, and not the allowed return on equity of 9.85 percent in 2005 and 2006, for purposes of calculating carrying cost credits for customers on the stranded cost deferrals. In addition, the DPU ordered WMECO not to combine certain overrecoveries and underrecoveries but instead, to keep them separate and to calculate carrying costs on certain balances using a return on equity of 11 percent and to use customer deposit rates on other balances. The impacts of this order on WMECO's calculations of the 2007 and year to date 2008 transition cost reconciliations were recorded in the second quarter of 2008.

On July 18, 2008, WMECO filed its 2007 transition cost reconciliation with the DPU. The schedule for reviewing this filing will be set by the DPU at a later date. Management does not expect the outcome of the DPU's review of this filing to have a material adverse effect on WMECO's net income, financial position or cash flows.

B.

Long-Term Contractual Arrangements (CL&P, Select Energy)

Estimated Future Annual CL&P Costs: The estimated future annual costs of CL&P s renewable energy contract arrangements, updated as of June 30, 2008, are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Total
Renewable energy contracts	$ 1.2	$ 18.0	$ 30.5	$ 71.9	$ 101.1	$ 1,558.9	$ 1,781.6

CL&P has entered into various agreements to purchase energy, capacity and renewable energy credits from renewable energy facilities. Amounts payable under these contracts are subject to a sharing agreement with UI, whereby UI will share 20 percent of the costs and benefits of these contracts. In addition, UI has entered into a contract that is subject to this cost sharing agreement under which CL&P will share in approximately 80 percent of the costs and benefits of the contract. The information in the table above includes 100 percent of the payments projected under the contracts entered into by CL&P and 80 percent of the payments projected under the contract entered into by UI. CL&P s portion of the costs and benefits of these contracts will be paid by or refunded to CL&P s customers.

Estimated Future Annual NU Enterprises Costs: The estimated future annual costs of NU Enterprises' significant contractual arrangements, updated as of June 30, 2008, are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Total
Select Energy purchase agreements	$ 30.0	$ 36.0	$ 38.4	$ 42.9	$ 38.8	$ 44.7	$ 230.8

Select Energy Purchase Agreements: Select Energy maintains long-term agreements to purchase energy as part of its portfolio of resources to meet its actual or expected sales commitments. Most purchase commitments are recorded at their mark-to-market value with the exception of one non-derivative contract which is accounted for on the accrual basis.

Select Energy's purchase commitment amounts are reported on a net basis in fuel, purchased and net interchange power along with certain sales contracts and mark-to-market amounts. Therefore, the amount included in fuel, purchased and net interchange power will be less than the amounts included in the table above. Select Energy also maintains certain energy commitments for which mark-to-market values have been recorded on the condensed consolidated balance sheets as derivative assets and liabilities. These contracts are included in the table above.

C.

Environmental Matters (HWP)

HWP is a subsidiary of NU that owns a minimal amount of transmission property and has limited operating activities. HWP continues to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP is at least partially responsible for this site, and has already conducted substantial remediation activities. HWP first established a reserve for this site in 1994. A pre-tax charge of approximately $3 million was recorded in the second quarter of 2008 to reflect the estimated cost of further tar delineation and site characterization studies, as well as certain remediation costs that are considered to be probable and estimable as of June 30, 2008. The cumulative expense recorded to this reserve through June 30, 2008 was approximately $15.9 million, of which $12.6 million had been spent, leaving approximately $3.3 million in the reserve as of June 30, 2008.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, which shares responsibility for the site, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP s 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP is developing plans for additional investigations to accord with MA DEP s guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

At this time, management believes that the $3.3 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $3.3 million to $4 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur through 2008 and 2009, and possibly into 2010.

There are many outcomes that could affect management's estimates and require an increase to the reserve, or range of costs, and a reserve increase would be reflected as a charge to pre-tax earnings. However, management cannot reasonably estimate the range of

additional investigation and remediation costs because they will depend on, among other things, the level and extent of the remaining tar that may be required to be remediated, the extent of HWP s responsibility and the related scope and timing, all of which are difficult to estimate because of a number of uncertainties at this time. As of June 30, 2008, HWP had $3.3 million remaining in the reserve related to this matter, and further developments may require a material increase to this reserve.

HWP's share of the remediation costs related to this site is not recoverable from customers.

D.

Guarantees and Indemnifications (All Companies)

NU provides credit assurances on behalf of subsidiaries in the form of guarantees and letters of credit (LOCs) in the normal course of business. NU has also provided guarantees and various indemnifications on behalf of external parties as a result of the sales of Select Energy Services, Inc. (SESI), NU Enterprises' retail marketing business and its competitive generation business. The following table summarizes NU's maximum exposure at June 30, 2008, in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," expiration dates, and fair value of amounts recorded.

Company	**Description**	**Maximum Exposure (in millions)**	**Expiration Date(s)**	**Fair Value of Amounts Recorded (in millions)**
On behalf of external parties:				
SESI	General indemnifications in connection with the sale of SESI including completeness and accuracy of information provided, compliance with laws, and various claims	Not Specified (1)	None	$ -
	Specific indemnifications in connection with the sale of SESI for	Not Specified (1)	Through project	$0.2

	estimated costs to complete or modify specific projects			completion	
	Indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts	$1.7		2017-2018	$0.1
	Surety bonds covering certain projects	$10.5		Through project completion	$ -
Hess Corporation (Retail Marketing Business)	General indemnifications in connection with the sale including compliance with laws, completeness and accuracy of information provided, and various claims	Not Specified	(1)	None	$ -
Energy Capital Partners (Competitive Generation Business)	General indemnifications in connection with the sale of NGC and the generating assets of Mt. Tom including compliance with tax and environmental laws, and various claims	Not Specified	(1)	2008-2009	$ -
On behalf of subsidiaries:					
Regulated Companies	Surety bonds, primarily for self-insurance	$13.6		None	N/A
	Letters of credit	$12.0		2009	N/A
Rocky River Realty Company	Lease payments for real estate	$11.2		2024	N/A
NUSCO	Lease payments for fleet of vehicles	$9.3		None	N/A
	Letters of credit	$6.0		2009	N/A
E.S. Boulos Company (Boulos)	Surety bonds covering ongoing projects	$73.3		Through project completion	N/A
NGS	Performance guarantee and insurance bonds	$22.1	(2)	2020 (2)	N/A

Select Energy	Performance guarantees and surety bonds for retail marketing contracts	$5.0 (3)	None (4)	N/A
	Performance guarantees for wholesale contracts	$26.7 (3)	2013	N/A
	Letters of credit	$2.0	2009	N/A

(1)

There is no specified maximum exposure included in the related sale agreements.

(2)

Included in the maximum exposure is $20.9 million related to a performance guarantee of Northeast Generation Services Company (NGS) obligations for which there is no specified maximum exposure in the agreement. The maximum exposure is calculated based on limits on NGS's liability contained in the underlying service contract and assumes that NGS will perform under that contract through its expiration in 2020. The remaining $1.2 million of maximum exposure relates to insurance bonds with no expiration date which are billed annually on their anniversary date.

(3)

Maximum exposure is as of June 30, 2008; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited.

(4)

NU does not currently anticipate that these remaining guarantees on behalf of Select Energy will result in significant guarantees of the performance of Hess Corporation.

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

In July 2006, under a guarantee of SESI obligations, NU purchased the right to receive contract payments relating to a SESI project that was financed and behind schedule. The carrying value of these assets was $8.8 million at June 30, 2008 and is included in other deferred debits on the accompanying condensed consolidated balance sheets. This carrying amount represents the net realizable value of the asset, which is subject to change through SESI's completion of the project. NU may record additional losses associated with this transaction, the amount of which will depend on the amount of project cash available to offset NU's costs and other factors.

6.

COMPREHENSIVE INCOME (NU, CL&P, PSNH, WMECO, NU Enterprises, Yankee Gas)

Total comprehensive income, which includes all comprehensive income/(loss) items, net of tax and by category, for the three and six months ended June 30, 2008 and 2007 is as follows:

	Three Months Ended June 30, 2008						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income/(loss)	$ 57.8	$ 44.8	$ 13.7	$ 3.3	$ 2.2	$ (1.0)	$ (5.2)
Comprehensive income/(loss) items:							
Qualified cash flow hedging instruments	12.9	4.9	1.7	-	-	2.5	3.8
(Decreases)/increases in unrealized gains on securities	(0.1)	-	-	(0.2)	-	-	0.1
Pension, SERP, and other postretirement benefits	0.9	-	-	-	0.7	-	0.2
Net change in comprehensive income/(loss) items	13.7	4.9	1.7	(0.2)	0.7	2.5	4.1
Total comprehensive income/(loss)	$ 71.5	$ 49.7	$ 15.4	$ 3.1	$ 2.9	$ 1.5	$ (1.1)

	Three Months Ended June 30, 2007						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income	$ 48.5	$ 24.4	$ 15.2	$ 4.6	$ 2.5	$ 0.3	$ 1.5
Comprehensive income items:							
Increase in unrealized gains on securities	1.2	-	0.1	-	-	-	1.1
Pension, SERP, and other postretirement benefits	5.8	-	-	-	3.6	-	2.2
Net change in comprehensive income items	7.0	-	0.1	-	3.6	-	3.3
	$ 55.5	$ 24.4	$ 15.3	$ 4.6	$ 6.1	$ 0.3	$ 4.8

Total comprehensive income

	Six Months Ended June 30, 2008						
(Millions of Dollars)	**NU***	**CL&P**	**PSNH**	**WMECO**	**NU Enterprises**	**Yankee Gas**	**Other**
Net income	$ 116.2	$ 89.5	$ 30.4	$ 9.6	$ 4.1	$ 17.6	$ (35.0)
Comprehensive (loss)/income items:							
Qualified cash flow hedging instruments	(5.8)	(3.6)	(1.5)	-	-	-	(0.7)
Decrease in unrealized gains on securities	(0.8)	-	-	(0.1)	-	-	(0.7)
Pension, SERP, and other postretirement benefits	2.1	-	-	-	1.0	-	1.1
Net change in comprehensive (loss)/income items	(4.5)	(3.6)	(1.5)	(0.1)	1.0	-	(0.3)
Total comprehensive income/(loss)	$ 111.7	$ 85.9	$ 28.9	$ 9.5	$ 5.1	$ 17.6	$ (35.3)

	Six Months Ended June 30, 2007						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income	$ 123.6	$ 58.0	$ 25.2	$ 11.5	$ 7.4	$ 13.9	$ 7.6
Comprehensive income/(loss) items:							
Qualified cash flow hedging instruments	(1.6)	(1.6)	-	-	-	-	-
Increase in unrealized gains on securities	1.4	-	0.1	-	-	-	1.3
Pension, SERP, and other postretirement benefits	6.3	-	-	-	3.9	-	2.4
Net change in comprehensive income/(loss) items	6.1	(1.6)	0.1	-	3.9	-	3.7
Total comprehensive income	$ 129.7	$ 56.4	$ 25.3	$ 11.5	$ 11.3	$ 13.9	$ 11.3

*After preferred dividends of subsidiary.

Comprehensive income amounts included in the Other column primarily relate to NU parent and Northeast Utilities Service Company (NUSCO).

Accumulated other comprehensive income fair value adjustments in NU's qualified cash flow hedging instruments for the six months ended June 30, 2008 and the twelve months ended December 31, 2007 are as follows:

(Millions of Dollars, Net of Tax)	Six Months Ended June 30, 2008	Twelve Months Ended December 31, 2007
Balance at beginning of period	$ 2.3	$ 5.9
Hedged transactions recognized into earnings	0.4	0.2
Change in fair value of interest rate swap agreements	(6.0)	-
Cash flow transactions entered into for the period	(0.2)	(3.8)

Net change associated with hedging transactions		(5.8)		(3.6)
Total fair value adjustments included in accumulated other comprehensive income	$	(3.5)	$	2.3

Yankee Gas has a forward interest rate swap agreement associated with its planned September 2008 long-term debt issuance. The fair value of the interest rate swap agreement is recorded in accumulated other comprehensive income with a corresponding pre-tax amount recorded as a derivative asset/liability. For the periods ended June 30, 2008 and December 31, 2007, a net of tax fair value benefit of $0.5 million was recorded in accumulated other comprehensive income. For further information, see Note 2, "Derivative Instruments," to the accompanying condensed consolidated financial statements.

In March 2008, PSNH terminated an interest rate swap agreement and recorded a $2.4 million net of tax settlement charge, net of hedge ineffectiveness of $0.2 million, in accumulated other comprehensive income.

The following table provides the forward starting interest rate swap transactions entered into by the company, CL&P and PSNH to hedge interest rate risk associated with their respective long-term debt issuances and terminated in May and June, 2008:

		NU Parent		CL&P		PSNH
Long-term debt issued (in millions)	$	250.0	$	300.0	$	110.0
Date issued		June 5, 2008		May 27, 2008		May 27, 2008
Term		5-year		10-year		10-year
Loaded LIBOR swap percentage rate(s) (percentage)		4.102 (1)		4.590 and 4.602 (2)		4.5575 (3)
Charge/(reduction) to accumulated other comprehensive income (net of tax) (4)		0.1		2.3		(1.5)

(1)

The interest rate swap was entered into with a notional amount of $200 million.

(2)

The two locked rates reflect two forward starting interest rate swap transactions, each with a notional amount of $150 million.

(3)

The first swap transaction was entered into in December 2007 and was replaced at its scheduled termination date in March 2008 with a new swap to extend the hedging relationship to the revised pricing date of the long-term debt in May 2008.

(4)

The charge to accumulated other comprehensive income will be amortized into earnings over the terms of each respective long-term debt.

It is estimated that a charge of $0.1 million will be reclassified from accumulated other comprehensive income as a decrease to earnings over the next 12 months as a result of amortization of amounts due to forward interest rate swap agreements that have been settled. Assuming the fair value of the existing forward interest rate swap agreement remains unchanged from June 30, 2008 to its planned settlement date in September 2008, it is estimated that $40 thousand will be reclassified from accumulated other comprehensive income as an increase to earnings over the next 12 months as a result of amortization of amounts due to the settlement of the forward interest rate swap agreement. At June 30, 2008, it is estimated that a pre-tax $0.1 million included in the accumulated other comprehensive income balance will be reclassified as an increase to earnings over the next 12 months related to Pension, SERP and other postretirement benefits adjustments.

7.

DISCONTINUED OPERATIONS (NU, NU Enterprises)

NU's condensed consolidated statements of income present NGC, Mt. Tom and SECI as discontinued operations. Under discontinued operations presentation, revenues and expenses of the businesses classified as discontinued operations are classified in loss from discontinued operations on the condensed consolidated statements of income, for all periods presented.

Summarized information for the discontinued operations is as follows:

	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars)	**June 30, 2008**	**June 30, 2007**	**June 30, 2008**	**June 30, 2007**
Operating revenues	$ -	$ 0.3	$ -	$ 1.1
Operating benefits/(expenses)	-	0.2	-	(0.9)
Income from discontinued operations	-	0.5	-	0.2
Gain from sale/disposition of discontinued operations	-	3.9	-	2.0
Income tax expense from discontinued operations	-	(1.9)	-	(1.0)
Net income from discontinued operations	-	2.5	-	1.2

The gain on sale/disposition of discontinued operations of $3.9 million for the three months ended June 30, 2007 was primarily due to the favorable resolution of contingencies from the completion of a cogeneration plant by SESI, which was sold in May of 2006, partially offset by charges related to the sale of the competitive generation business. In the first quarter of 2007, a $1.9 million charge resulted from a purchase price adjustment from the sale of the competitive generation business.

No intercompany revenues were included in discontinued operations for either of the three and six months ended June 30, 2008 and 2007.

At June 30, 2008, NU did not have and does not expect to have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations.

8.

EARNINGS PER SHARE (NU)

Earnings per share (EPS) is computed based upon the weighted average number of common shares outstanding, excluding unallocated Employee Stock Ownership Plan (ESOP) shares, during each period. Diluted EPS is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common stock. There were no antidilutive options for any of the three- and six-month periods ended June 30, 2008 and 2007.

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

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars, Except for Share Information)		**2008**		**2007**		**2008**		**2007**
Income from continuing operations	$	57.8	$	46.0	$	116.2	$	122.4
Income from discontinued operations		-		2.5		-		1.2
Net income	$	57.8	$	48.5	$	116.2	$	123.6
Basic EPS common shares outstanding (average)		155,476,492		154,729,676		155,381,302		154,539,678
Dilutive effect		418,856		483,418		427,179		562,994
Fully diluted EPS common shares outstanding (average)		155,895,348		155,213,094		155,808,481		155,102,672

Basic and Fully Diluted EPS:								
Income from continuing operations	$	0.37	$	0.30	$	0.75	$	0.79
Income from discontinued operations		-		0.01		-		0.01
Net income	$	0.37	$	0.31	$	0.75	$	0.80

Restricted share units (RSUs) are included in basic common shares outstanding when shares are both vested and issued. The dilutive effect of RSUs granted but not issued is calculated using the treasury stock method. Assumed proceeds of RSUs 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 RSUs (the difference between the market value of RSUs using the average market price during the period and the grant date market value).

The dilutive effect of stock options 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 common shares underlying the stock options outstanding for the period using the average market price and the exercise price on the date of grant).

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

9.

LONG-TERM DEBT (NU, CL&P, PSNH)

NU parent, CL&P and PSNH issued long-term debt in the three months ended June 30, 2008. The details of this issuance are as follows:

(Millions of Dollars)		
Senior Notes:		
NU Parent:		
5.65% Series C due 2013	$	250
First Mortgage Bonds:		
CL&P:		
5.65% 2008 Series A due 2018		300
PSNH:		
6.00% Series O due 2018		110
Total Long-Term Debt Issued	$	660

The proceeds from the NU parent long-term debt issuance were used to repay the $150 million long-term Series B senior note with an interest rate of 3.3 percent which matured on June 1, 2008 and short-term borrowings outstanding under a credit facility. The proceeds from the CL&P and PSNH long-term debt issuances were used to repay short-term debt, to fund each company's capital programs, and for general working capital purposes.

These long-term debt agreements require each company to comply with certain covenants as are customarily included in such agreements. The parties to these agreements currently are and expect to remain in compliance with these covenants.

10.

SEGMENT INFORMATION (All Companies)

Presentation: NU is organized between the regulated companies and NU Enterprises' businesses 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 and the capitalized portion of pension expense or income. Segment information for all periods presented has been reclassified to conform to the current period presentation, except as indicated.

The regulated companies segment, including the electric distribution, generation and transmission segments, as well as the gas distribution segment (Yankee Gas), represented approximately 99 percent of NU's total revenues for the three and six months ended June 30, 2008 as compared to 95 percent and 96 percent, respectively, for the 2007 periods. CL&P's, PSNH's and WMECO's complete condensed consolidated financial statements are included in this combined quarterly report on Form 10-Q. PSNH's distribution segment includes generation activities. Also included in this combined quarterly report on Form 10-Q is detailed information regarding CL&P's, PSNH's, and WMECO's transmission segments.

At June 30, 2008, the NU Enterprises business segment included the following legal entities: 1) Select Energy (wholesale contracts), 2) NGS, 3) Boulos, and 4) NU Enterprises parent.

Other in the segment tables primarily consists of 1) the results of NU parent, which include 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 Northeast

Utilities Services Company, most of which are eliminated in consolidation, and 3) the results of other subsidiaries, which include The Rocky River Realty Company and The Quinnehtuk Company (real estate subsidiaries), Mode 1 Communications, Inc. and the non-utility subsidiaries of Yankee Energy System, Inc. (Yankee Energy Services Company, Yankee Energy Financial Services Company and NorConn Properties, Inc.).

Effective January 1, 2007, financial information for the remaining operations of HWP that were not exited as part of the sale of the competitive generation business was included as part of the Other reportable segment as these operations were no longer considered part of NU Enterprises subsequent to the sale. Accordingly, HWP's remaining operations have been presented as part of the Other reportable segment for each of the three and six months ended June 30, 2008 and 2007.

NU's condensed consolidated statements of income for the three and six months ended June 30, 2007 present the remaining activity for NGC, Mt. Tom and SECI as discontinued operations. For further information and information regarding the exit from these businesses, see Note 7, "Discontinued Operations," to the condensed consolidated financial statements.

NU's segment information for the three and six months ended June 30, 2008 and 2007 is as follows (certain amounts presented in the financial statements may differ from amounts presented in the segment schedules due to rounding):

	For the Three Months Ended June 30, 2008						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,098.7	$ 113.0	$ 101.4	$ 30.0	$ 100.2	$ (118.0)	$ 1,325.3
Depreciation and amortization	(136.9)	(6.6)	(11.6)	(0.1)	(3.1)	0.2	(158.1)
Other operating expenses	(889.0)	(103.3)	(33.4)	(25.1)	(95.4)	117.1	(1,029.1)
Operating income/(loss)	72.8	3.1	56.4	4.8	1.7	(0.7)	138.1
Interest expense, net of AFUDC	(41.6)	(4.9)	(11.8)	(1.3)	(9.1)	2.6	(66.1)
Interest income	1.0	-	1.6	0.2	2.3	(3.6)	1.5
Other income, net	1.6	-	7.2	-	36.4	(36.3)	8.9
	(6.3)	0.8	(17.7)	(1.5)	1.9	(0.4)	(23.2)

Income tax (expense)/benefit							
Preferred dividends	(0.9)	-	(0.5)	-	-	-	(1.4)
Net income	$ 26.6	$ (1.0)	$ 35.2	$ 2.2	$ 33.2	$ (38.4)	$ 57.8

For the Six Months Ended June 30, 2008

(Millions of Dollars)	Regulated Companies Distribution (1) Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 2,296.8	$ 312.6	$ 196.3	$ 63.9	$ 200.1	$ (224.4)	$ 2,845.3
Depreciation and amortization	(265.8)	(13.0)	(22.3)	(0.3)	(7.1)	0.4	(308.1)
Other operating expenses	(1,870.7)	(261.6)	(65.1)	(54.3)	(236.1)	221.0	(2,266.8)
Operating income/(loss)	160.3	38.0	108.9	9.3	(43.1)	(3.0)	270.4
Interest expense, net of AFUDC	(83.2)	(10.1)	(22.2)	(3.0)	(15.0)	4.8	(128.7)
Interest income	1.9	-	2.0	0.6	4.0	(5.8)	2.7
Other income, net	8.4	0.1	12.6	-	110.4	(110.3)	21.2
Income tax (expense)/benefit	(23.8)	(10.4)	(32.6)	(2.8)	24.0	(1.0)	(46.6)
Preferred dividends	(1.8)	-	(1.0)	-	-	-	(2.8)
Net income	$ 61.8	$ 17.6	$ 67.7	$ 4.1	$ 80.3	$ (115.3)	$ 116.2
Total assets (2)	$ 11,160.0	$ 1,280.8	$ -	$ 111.3	$ 4,232.2	$ (4,075.0)	$ 12,709.3
Cash flows for total investments in plant	$ 205.5	$ 23.4	$ 383.6	$ -	$ 12.6	$ -	$ 625.1

For the Three Months Ended June 30, 2007

(Millions of Dollars)	Regulated Companies Distribution (1) Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,160.0	$ 95.0	$ 73.0	$ 72.2	$ 99.9	$ (108.3)	$ 1,391.8
Depreciation and amortization	(90.9)	(5.8)	(9.2)	(0.1)	(1.7)	0.7	(107.0)

Other operating expenses	(998.0)	(85.2)	(27.1)	(70.6)	(93.7)	106.6	(1,168.0)
Operating income	71.1	4.0	36.7	1.5	4.5	(1.0)	116.8
Interest expense, net of AFUDC	(41.4)	(4.2)	(8.3)	(2.3)	(8.9)	5.5	(59.6)
Interest income	1.0	-	0.7	0.8	7.6	(5.4)	4.7
Other income, net	3.8	0.5	2.6	-	29.5	(29.2)	7.2
Income tax expense	(10.5)	-	(10.1)	-	(0.5)	(0.6)	(21.7)
Preferred dividends	(0.9)	-	(0.5)	-	-	-	(1.4)
Income from continuing operations	23.1	0.3	21.1	-	32.2	(30.7)	46.0
Income from discontinued operations	-	-	-	2.5	-	-	2.5
Net income	$ 23.1	$ 0.3	$ 21.1	$ 2.5	$ 32.2	$ (30.7)	$ 48.5

(Millions of Dollars)	For the Six Months Ended June 30, 2007 Regulated Companies Distribution (1) Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 2,541.4	$ 279.8	$ 141.8	$ 152.1	$ 193.9	$ (213.7)	$ 3,095.3
Depreciation and amortization	(196.1)	(11.6)	(18.2)	(0.3)	(4.1)	1.7	(228.6)
Other operating expenses	(2,187.2)	(239.6)	(55.4)	(140.1)	(181.7)	209.8	(2,594.2)
Operating income	158.1	28.6	68.2	11.7	8.1	(2.2)	272.5
Interest expense, net of AFUDC	(83.8)	(8.5)	(17.1)	(5.3)	(17.1)	12.9	(118.9)
Interest income	2.0	-	1.1	1.3	20.3	(12.8)	11.9
Other income, net	8.0	1.0	3.9	-	86.0	(84.8)	14.1
Income tax expense	(24.6)	(7.2)	(18.3)	(1.5)	(1.7)	(1.1)	(54.4)
Preferred dividends	(2.0)	-	(0.8)	-	-	-	(2.8)
Income from continuing operations	57.7	13.9	37.0	6.2	95.6	(88.0)	122.4
Income from discontinued operations	-	-	-	1.2	-	-	1.2
Net income	$ 57.7	$ 13.9	$ 37.0	$ 7.4	$ 95.6	$ (88.0)	$ 123.6
Cash flows for total investments in plant	$ 184.4	$ 29.2	$ 270.2	$ 1.2	$ 6.1	$ -	$ 491.1

(1)

Includes PSNH's generation activities.

(2)

Information for segmenting total assets between electric distribution and transmission is not available at June 30, 2008. On an NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution columns above.

The regulated companies information related to the distribution and transmission segments for CL&P, PSNH and WMECO for the three and six months ended June 30, 2008 and 2007 is as follows:

	CL&P - For the Three Months Ended June 30, 2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 741.7	$ 80.2	$ 821.9
Depreciation and amortization	(120.8)	(9.2)	(130.0)
Other operating expenses	(579.4)	(22.9)	(602.3)
Operating income	41.5	48.1	89.6
Interest expense, net of AFUDC	(26.3)	(10.1)	(36.4)
Interest income	0.7	1.0	1.7
Other income, net	1.5	6.4	7.9
Income tax expense	(1.7)	(14.9)	(16.6)
Preferred dividends	(0.9)	(0.5)	(1.4)
Net income	$ 14.8	$ 30.0	$ 44.8

	CL&P - For the Six Months Ended June 30, 2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 1,553.8	$ 153.6	$ 1,707.4
Depreciation and amortization	(208.8)	(17.6)	(226.4)
Other operating expenses	(1,255.0)	(46.6)	(1,301.6)
Operating income	90.0	89.4	179.4
Interest expense, net of AFUDC	(52.6)	(18.8)	(71.4)
Interest income	1.3	1.4	2.7
Other income, net	7.9	11.2	19.1
Income tax expense	(11.1)	(26.4)	(37.5)
Preferred dividends	(1.8)	(1.0)	(2.8)
Net income	$ 33.7	$ 55.8	$ 89.5
Cash flows for total investments in plant	$ 119.4	$ 322.6	$ 442.0

	CL&P - For the Three Months Ended June 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 814.2	$ 56.2	$ 870.4
Depreciation and amortization	(72.1)	(7.1)	(79.2)
Other operating expenses	(708.0)	(19.2)	(727.2)
Operating income	34.1	29.9	64.0
Interest expense, net of AFUDC	(26.0)	(6.9)	(32.9)
Interest income	0.7	0.5	1.2
Other income, net	3.2	2.4	5.6
Income tax expense	(4.1)	(8.0)	(12.1)
Preferred dividends	(0.9)	(0.5)	(1.4)
Net income	$ 7.0	$ 17.4	$ 24.4

	CL&P - For the Six Months Ended June 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 1,805.5	$ 108.6	$ 1,914.1
Depreciation and amortization	(138.6)	(14.1)	(152.7)
Other operating expenses	(1,579.2)	(39.3)	(1,618.5)
Operating income	87.7	55.2	142.9
Interest expense, net of AFUDC	(53.9)	(14.1)	(68.0)
Interest income	1.4	0.9	2.3
Other income, net	7.0	3.5	10.5
Income tax expense	(12.6)	(14.3)	(26.9)
Preferred dividends	(2.0)	(0.8)	(2.8)
Net income	$ 27.6	$ 30.4	$ 58.0
Cash flows for total investments in plant	$ 112.6	$ 240.6	$ 353.2

	PSNH - For the Three Months Ended June 30, 2008		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Total**
Operating revenues	$ 259.2	$ 14.8	$ 274.0
Depreciation and amortization	(4.5)	(1.8)	(6.3)
Other operating expenses	(230.7)	(7.0)	(237.7)
Operating income	24.0	6.0	30.0
Interest expense, net of AFUDC	(10.9)	(1.2)	(12.1)

Interest income	0.2	0.4	0.6
Other income, net	0.2	0.5	0.7
Income tax expense	(3.4)	(2.1)	(5.5)
Net income	$ 10.1	$ 3.6	$ 13.7

	PSNH - For the Six Months Ended June 30, 2008		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Total**
Operating revenues	$ 535.9	$ 29.9	$ 565.8
Depreciation and amortization	(34.7)	(3.4)	(38.1)
Other operating expenses	(450.5)	(12.3)	(462.8)
Operating income	50.7	14.2	64.9
Interest expense, net of AFUDC	(21.8)	(2.3)	(24.1)
Interest income	0.3	0.4	0.7
Other income, net	0.6	1.3	1.9
Income tax expense	(8.2)	(4.8)	(13.0)
Net income	$ 21.6	$ 8.8	$ 30.4
Cash flows for total investments in plant	$ 71.6	$ 47.6	$ 119.2

	PSNH - For the Three Months Ended June 30, 2007		
(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	$ 239.1	$ 11.1	$ 250.2
Depreciation and amortization	(9.1)	(1.4)	(10.5)
Other operating expenses	(203.2)	(4.9)	(208.1)
Operating income	26.8	4.8	31.6
Interest expense, net of AFUDC	(10.6)	(1.0)	(11.6)
Interest income	0.1	0.1	0.2
Other income, net	0.3	0.1	0.4
Income tax expense	(4.0)	(1.4)	(5.4)
Net income	$ 12.6	$ 2.6	$ 15.2

	PSNH - For the Six Months Ended June 30, 2007		
(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	$ 505.3	$ 22.0	$ 527.3
Depreciation and amortization	(37.7)	(2.8)	(40.5)
Other operating expenses	(420.7)	(10.5)	(431.2)
Operating income	46.9	8.7	55.6
Interest expense, net of AFUDC	(21.0)	(2.1)	(23.1)
Interest income	0.3	0.1	0.4
Other income, net	0.6	0.4	1.0
Income tax expense	(6.1)	(2.6)	(8.7)
Net income	$ 20.7	$ 4.5	$ 25.2
Cash flows for total investments in plant	$ 56.8	$ 22.7	$ 79.5

(1)

Includes PSNH's generation activities.

	WMECO - For the Three Months Ended June 30, 2008		
(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	$ 97.8	$ 6.4	$ 104.2
Depreciation and amortization	(11.6)	(0.7)	(12.3)

Other operating expenses		(79.0)		(3.3)		(82.3)
Operating income		7.2		2.4		9.6
Interest expense, net of AFUDC		(4.4)		(0.4)		(4.8)
Interest income		0.2		0.2		0.4
Other income, net		-		0.1		0.1
Income tax expense		(1.3)		(0.7)		(2.0)
Net income	$	1.7	$	1.6	$	3.3

	WMECO - For the Six Months Ended June 30, 2008					
(Millions of Dollars)	**Distribution**		**Transmission**		**Total**	
Operating revenues	$	207.3	$	12.7	$	220.0
Depreciation and amortization		(22.4)		(1.3)		(23.7)
Other operating expenses		(165.4)		(6.1)		(171.5)
Operating income		19.5		5.3		24.8
Interest expense, net of AFUDC		(8.8)		(1.2)		(10.0)
Interest income		0.3		0.3		0.6
Other income, net		-		0.2		0.2
Income tax expense		(4.5)		(1.5)		(6.0)
Net income	$	6.5	$	3.1	$	9.6
Cash flows for total investments in plant	$	14.6	$	13.3	$	27.9

	WMECO - For the Three Months Ended June 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 106.7	$ 5.7	$ 112.4
Depreciation and amortization	(9.6)	(0.7)	(10.3)
Other operating expenses	(86.8)	(3.0)	(89.8)
Operating income	10.3	2.0	12.3
Interest expense, net of AFUDC	(4.7)	(0.4)	(5.1)
Interest income	0.1	0.1	0.2
Other income, net	0.2	0.1	0.3
Income tax expense	(2.4)	(0.7)	(3.1)
Net income	$ 3.5	$ 1.1	$ 4.6

	WMECO - For the Six Months Ended June 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 230.6	$ 11.3	$ 241.9
Depreciation and amortization	(19.8)	(1.3)	(21.1)
Other operating expenses	(187.4)	(5.7)	(193.1)
Operating income	23.4	4.3	27.7
Interest expense, net of AFUDC	(8.9)	(0.9)	(9.8)
Interest income	0.3	0.1	0.4
Other income, net	0.5	-	0.5
Income tax expense	(5.9)	(1.4)	(7.3)
Net income	$ 9.4	$ 2.1	$ 11.5
Cash flows for total investments in plant	$ 15.0	$ 6.9	$ 21.9

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, 2008, and the related condensed consolidated statements of income for the three-month and six-month periods ended June 30, 2008 and 2007, and of cash flows for the six-month periods ended June 30, 2008 and 2007. 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.

As discussed in Notes 1.C. and 3., the Company adopted Statement of Financial Accounting Standard No. 157, *Fair Value Measurements*, as of January 1, 2008.

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 Northeast Utilities and subsidiaries as of December 31, 2007, and the related consolidated statements of income, comprehensive income, shareholders equity, and cash flows for the year then ended (not presented herein); and in our report dated February 28, 2008 (which report included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109*, as of January 1, 2007), 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, 2007 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 6, 2008

This Page Intentionally Left Blank

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 17	$ 538
Investments in securitizable assets (Note 1E)	-	308,182
Receivables, less provision for uncollectible accounts of $20,787 in 2008 and $7,874 in 2007	348,544	118,342
Accounts receivable from affiliated companies	8,798	3,339
Unbilled revenues	117,906	8,225
Taxes receivable	-	16,245
Materials and supplies	66,041	55,477
Derivative assets - current	90,013	57,003
Prepayments and other	9,514	17,387
	640,833	584,738
Property, Plant and Equipment:		
Electric utility	5,189,098	4,899,075
Less: Accumulated depreciation	1,318,485	1,279,697
	3,870,613	3,619,378
Construction work in progress	926,880	782,468
	4,797,493	4,401,846

Deferred Debits and Other Assets:				
Regulatory assets		1,778,353		1,329,963
Prepaid pension		351,517		334,786
Derivative assets - long-term		392,777		278,726
Other		75,222		88,040
		2,597,869		2,031,515
Total Assets	$	8,036,195	$	7,018,099

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to affiliated companies	$ 52,325	$ 38,825
Accounts payable	369,577	368,356
Accounts payable to affiliated companies	41,801	53,096
Accrued taxes	24,707	-
Accrued interest	33,444	29,532
Derivative liabilities - current	2,113	4,234
Counterparty deposits	24,825	-
Other	119,336	107,940
	668,128	601,983
Rate Reduction Bonds	464,746	548,686
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	761,364	698,789
Accumulated deferred investment tax credits	20,109	21,412
Deferred contractual obligations	141,485	152,735
Regulatory liabilities	599,789	601,455
Derivative liabilities - long-term	725,613	135,991
Accrued postretirement benefits	74,066	78,587
Other	201,744	191,464
	2,524,170	1,880,433
Capitalization:		
Long-Term Debt	2,330,694	2,028,546

Preferred Stock - Non-Redeemable	116,200	116,200
Common Stockholder's Equity:		
Common stock, $10 par value - authorized		
24,500,000 shares; 6,035,205 shares outstanding		
in 2008 and 2007	60,352	60,352
Capital surplus, paid in	1,301,226	1,243,940
Retained earnings	574,451	538,138
Accumulated other comprehensive loss	(3,772)	(179)
Common Stockholder's Equity	1,932,257	1,842,251
Total Capitalization	4,379,151	3,986,997
Commitments and Contingencies (Note 5)		
.		
Total Liabilities and Capitalization	$ 8,036,195	$ 7,018,099

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Thousands of Dollars)			
Operating Revenues	$ 821,875	$ 870,379	$ 1,707,374	$ 1,914,065
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	398,085	516,270	891,893	1,205,043
Other	132,329	143,664	261,372	277,238
Maintenance	33,154	29,456	62,434	50,890
Depreciation	39,855	38,293	78,724	76,482
Amortization of regulatory assets, net	56,404	9,649	75,988	9,319
Amortization of rate reduction bonds	33,649	31,268	71,680	66,929
Taxes other than income taxes	38,764	37,828	85,834	85,249
Total operating expenses	732,240	806,428	1,527,925	1,771,150
Operating Income	89,635	63,951	179,449	142,915
Interest Expense:				
Interest on long-term debt	25,392	21,564	48,999	39,180
Interest on rate reduction bonds	7,595	9,747	15,811	19,867
Other interest	3,404	1,630	6,561	8,952
Interest expense, net	36,391	32,941	71,371	67,999

Other Income, Net	9,575	6,879	21,698	12,730
Income Before Income Tax Expense	62,819	37,889	129,776	87,646
Income Tax Expense	16,564	12,103	37,453	26,866
Net Income	$ 46,255	$ 25,786	$ 92,323	$ 60,780

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 92,323	$ 60,780
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	3,042	9,699
Depreciation	78,724	76,482
Deferred income taxes	49,945	(13,111)
Pension income, net of capitalized portion	(5,681)	(4,097)
Amortization of recoverable energy costs	-	2,064
Amortization of rate reduction bonds	71,680	66,929
Amortization of regulatory assets, net	75,988	9,319
Regulatory (refunds and underrecoveries)/overrecoveries	(133,161)	41,371
Settlement of cash flow hedge instruments	(3,890)	-
Deferred contractual obligations	(11,250)	(15,762)
Other non-cash adjustments	(12,301)	(7,442)
Other uses of cash	(7,297)	(11,915)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(18,814)	(8,708)
Materials and supplies	(10,569)	(7,996)
Investments in securitizable assets	(25,787)	17,675
Other current assets	7,794	4,440
Accounts payable	(21,439)	(18,242)
Taxes receivable/accrued	47,209	(150,041)
Counterparty deposits	24,825	-
Other current liabilities	6,586	6,938
Net cash flows provided by operating activities	207,927	58,383

Investing Activities:				
Investments in property and plant		(442,014)		(353,241)
Proceeds from sales of investment securities		1,322		858
Purchases of investment securities		(1,353)		(896)
Rate reduction bond escrow and other deposits		5,643		5,128
Other investing activities		623		648
Net cash flows used in investing activities		(435,779)		(347,503)
Financing Activities:				
Issuance of long-term debt		300,000		300,000
Retirement of rate reduction bonds		(83,940)		(77,796)
Increase/(decrease) in NU Money Pool borrowings		13,500		(102,200)
Capital contributions from NU parent		57,058		215,000
Cash dividends on preferred stock		(2,779)		(2,779)
Cash dividends on common stock		(53,231)		(39,591)
Other financing activities		(3,277)		(4,818)
Net cash flows provided by financing activities		227,331		287,816
Net decrease in cash		(521)		(1,304)
Cash - beginning of period		538		3,310
Cash - end of period	$	17	$	2,006

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

This Page Intentionally Left Blank

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 224	$ 450
Receivables, less provision for uncollectible accounts of $3,201 in 2008 and $2,675 in 2007	85,787	97,749
Accounts receivable from affiliated companies	5,564	817
Unbilled revenues	50,626	45,607
Notes receivable from affiliated companies	16,200	-
Taxes receivable	37,335	255
Fuel, materials and supplies	81,891	72,215
Derivative assets - current	64,778	6,146
Prepayments and other	15,322	14,327
	357,727	237,566
Property, Plant and Equipment:		
Electric utility	2,132,769	2,010,220
Less: Accumulated depreciation	759,136	737,917
	1,373,633	1,272,303
Construction work in progress	95,325	116,102
	1,468,958	1,388,405
Deferred Debits and Other Assets:		
Regulatory assets	374,076	401,374
Derivative assets - long-term	27,984	12,075
Other	64,676	67,549
	466,736	480,998

Total Assets	$ 2,293,421	$ 2,106,969

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ -	$ 10,000
Notes payable to affiliated companies	-	11,300
Accounts payable	84,994	91,356
Accounts payable to affiliated companies	19,032	15,717
Accrued interest	9,850	9,175
Derivative liabilities - current	-	2,453
Other	50,347	22,664
	164,223	162,665
Rate Reduction Bonds	257,638	282,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	169,508	192,094
Accumulated deferred investment tax credits	468	582
Deferred contractual obligations	25,525	28,215
Regulatory liabilities	185,428	127,569
Accrued pension	144,001	138,346
Accrued postretirement benefits	27,765	29,057
Other	47,965	31,559
	600,660	547,422
Capitalization:		
Long-Term Debt	686,753	576,997
Common Stockholder's Equity:		

Common stock, $1 par value - authorized 100,000,000 shares; 301 shares outstanding in 2008 and 2007		-	-
Capital surplus, paid in		311,159	275,569
Retained earnings		273,720	261,528
Accumulated other comprehensive (loss)/income		(732)	770
Common Stockholder's Equity		584,147	537,867
Total Capitalization		1,270,900	1,114,864
Commitments and Contingencies (Note 5)			
Total Liabilities and Capitalization	$	2,293,421	$ 2,106,969

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Thousands of Dollars)			
Operating Revenues	$ 274,039	$ 250,233	$ 565,804	$ 527,329
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	142,534	126,187	284,435	268,612
Other	55,861	49,488	109,107	102,539
Maintenance	29,283	22,708	49,173	40,112
Depreciation	13,720	13,354	27,222	26,643
Amortization of regulatory liabilities, net	(18,319)	(15,503)	(11,911)	(11,709)
Amortization of rate reduction bonds	10,870	12,697	22,747	25,603
Taxes other than income taxes	10,045	9,734	20,121	19,884
Total operating expenses	243,994	218,665	500,894	471,684
Operating Income	30,045	31,568	64,910	55,645
Interest Expense:				
Interest on long-term debt	7,721	6,254	14,999	12,405
	4,081	4,603	8,232	9,311

Interest on rate reduction bonds				
Other interest	332	787	890	1,380
Interest expense, net	12,134	11,644	24,121	23,096
Other Income, Net	1,262	720	2,588	1,393
Income Before Income Tax Expense	19,173	20,644	43,377	33,942
Income Tax Expense	5,482	5,399	12,997	8,730
Net Income	$ 13,691	$ 15,245	$ 30,380	$ 25,212

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Thousands of Dollars)	
Operating activities:		
Net income	$ 30,380	$ 25,212
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	2,523	1,407
Depreciation	27,222	26,643
Deferred income taxes	4,144	58
Pension expense, net of capitalized portion	6,796	7,718
Amortization of rate reduction bonds	22,747	25,603
Amortization of regulatory liabilities, net	(11,911)	(11,709)
Regulatory refunds and underrecoveries	(545)	(3,473)
Net settlement of cash flow hedge instruments	(1,730)	-
Deferred contractual obligations	(2,690)	(3,463)
Other non-cash adjustments	(3,789)	(2,967)
Other uses of cash	(5,176)	(11,730)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(327)	4,312
Taxes receivable/accrued	(24,739)	(13,583)
Fuel, materials and supplies	(9,676)	7,892
Other current assets	870	(5,739)
Accounts payable	15,293	2,105
Other current liabilities	2,749	4,291
Net cash flows provided by operating activities	52,141	52,577
Investing Activities:		
Investments in property and plant	(119,208)	(79,470)

Increase in NU Money Pool lending		(16,200)		-
Proceeds from sales of investment securities		2,265		1,471
Purchases of investment securities		(2,319)		(1,536)
Other investing activities		3,007		1,779
Net cash flows used in investing activities		(132,455)		(77,756)
Financing Activities:				
Issuance of long-term debt		110,000		-
Decrease in short-term debt		(10,000)		-
Retirement of rate reduction bonds		(24,380)		(25,527)
(Decrease)/increase in NU Money Pool borrowings		(11,300)		36,700
Capital contributions from NU parent		35,500		29,500
Cash dividends on common stock		(18,188)		(15,359)
Other financing activities		(1,544)		(83)
Net cash flows provided by financing activities		80,088		25,231
Net (decrease)/increase in cash		(226)		52
Cash - beginning of period		450		31
Cash - end of period	$	224	$	83

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

This Page Intentionally Left Blank

WESTERN MASSACHUSETTS ELECTRIC COMPANY

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 2,094	$ 1,110
Receivables, less provision for uncollectible accounts of $6,744 in 2008 and $5,699 in 2007	48,622	49,578
Accounts receivable from affiliated companies	2,727	258
Unbilled revenues	16,086	17,990
Taxes receivable	15,885	3,382
Materials and supplies	3,319	2,353
Marketable securities - current	44,863	31,286
Prepayments and other	4,371	2,661
	137,967	108,618
Property, Plant and Equipment:		
Electric utility	749,835	728,712
Less: Accumulated depreciation	211,834	205,743
	538,001	522,969
Construction work in progress	42,846	36,388
	580,847	559,357
Deferred Debits and Other Assets:		
Regulatory assets	173,878	193,921
Prepaid pension	93,804	90,015
Marketable securities - long-term	11,854	25,078
Other	14,234	14,099

		293,770		323,113
Total Assets	$	1,012,584	$	991,088

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

WESTERN MASSACHUSETTS ELECTRIC
COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED
BALANCE SHEETS
(Unaudited)

	June 30, 2008	December 31, 2007
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to affiliated companies	$ 3,300	$ 14,900
Accounts payable	32,147	30,636
Accounts payable to affiliated companies	10,062	7,480
Accrued interest	5,418	5,498
Counterparty deposits	9,019	-
Other	10,904	10,489
	70,850	69,003
Rate Reduction Bonds	79,876	86,731
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	188,245	187,139
Accumulated deferred investment tax credits	1,884	2,015
Deferred contractual obligations	38,925	41,958
Regulatory liabilities	36,369	39,437
Accrued postretirement benefits	11,855	12,668
Other	17,273	5,015
	294,551	288,232
Capitalization:		
Long-Term Debt	305,038	303,872
Common Stockholder's Equity:		
Common stock, $25 par value - authorized		

1,072,471 shares; 434,653 shares outstanding			
in 2008 and 2007		10,866	10,866
Capital surplus, paid in		144,544	128,228
Retained earnings		106,757	103,925
Accumulated other comprehensive income		102	231
Common Stockholder's Equity		262,269	243,250
Total Capitalization		567,307	547,122
Commitments and Contingencies (Note 5)			
Total Liabilities and Capitalization	$	1,012,584	$ 991,088

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Thousands of Dollars)			
Operating Revenues	$ 104,215	$ 112,363	$ 219,974	$ 241,921
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	51,355	56,736	113,494	127,907
Other	22,467	25,037	41,575	49,464
Maintenance	5,472	4,985	10,049	9,317
Depreciation	5,251	5,238	10,444	10,486
Amortization of regulatory assets, net	3,654	1,926	6,409	4,215
Amortization of rate reduction bonds	3,365	3,151	6,807	6,382
Taxes other than income taxes	3,008	2,976	6,374	6,401
Total operating expenses	94,572	100,049	195,152	214,172
Operating Income	9,643	12,314	24,822	27,749
Interest Expense:				
Interest on long-term debt	3,263	2,656	6,686	5,305
Interest on rate reduction bonds	1,312	1,490	2,660	3,011
Other interest	274	963	625	1,528
Interest expense, net	4,849	5,109	9,971	9,844
Other Income, Net	477	448	724	936
	5,271	7,653	15,575	18,841

Income Before Income Tax Expense				
Income Tax Expense	2,022	3,063	6,006	7,334
Net Income	$ 3,249	$ 4,590	$ 9,569	$ 11,507

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
	2008	2007
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 9,569	$ 11,507
Adjustments to reconcile to net cash flows provided by/(used in) operating activities:		
Bad debt expense	4,022	3,282
Depreciation	10,444	10,486
Deferred income taxes	3,546	(8,590)
Pension income, net of capitalized portion	(1,885)	(1,500)
Amortization of rate reduction bonds	6,807	6,382
Amortization of regulatory assets, net	6,409	4,215
Regulatory overrecoveries	1,755	24,642
Deferred contractual obligations	(3,033)	(4,264)
Other non-cash adjustments	(1,163)	(1,507)
Other sources of cash	-	370
Other uses of cash	(1,267)	(398)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(3,432)	(13,083)
Materials and supplies	(984)	50
Other current assets	184	(942)
Accounts payable	53	(1,782)
Taxes receivable/accrued	(2,338)	(34,746)
Counterparty deposits	9,019	-
Other current liabilities	173	274
Net cash flows provided by/(used in) operating activities	37,879	(5,604)

Investing Activities:				
Investments in property and plant		(27,945)		(21,921)
Proceeds from sales of investment securities		90,755		76,427
Purchases of investment securities		(91,180)		(78,118)
Other investing activities		386		(5)
Net cash flows used in investing activities		(27,984)		(23,617)
Financing Activities:				
Retirement of rate reduction bonds		(6,855)		(6,433)
(Decrease)/increase in NU Money Pool borrowings		(11,600)		37,000
Capital contributions from NU parent		16,281		4,800
Cash dividends on common stock		(6,737)		(6,389)
Net cash flows (used in)/provided by financing activities		(8,911)		28,978
Net increase/(decrease) in cash		984		(243)
Cash - beginning of period		1,110		1,336
Cash - end of period	$	2,094	$	1,093

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

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 the condensed consolidated financial statements and related notes included in this Quarterly Report on Form 10-Q, Northeast Utilities and subsidiaries combined first quarter 2008 Quarterly Report on Form 10-Q (the First Quarter 2008 Form 10-Q) and the Northeast Utilities and subsidiaries combined 2007 Annual Report on Form 10-K (2007 Form 10-K) as filed with the Securities and Exchange Commission (SEC). References in this Form 10-Q to "NU" or "the company" are to Northeast Utilities combined with its subsidiaries, and the terms "we," "us" and "our" refer to NU. All per share amounts are reported on a fully diluted basis.

The only common equity securities that are publicly traded are common shares of NU. The earnings per share (EPS) of each segment discussed below does not represent a direct legal interest in the assets and liabilities allocated to such segment but rather represents a direct interest in our assets and liabilities as a whole. EPS by segment is a measure not recognized under accounting principles generally accepted in the United States of America (GAAP) that is calculated by dividing the net income or loss of each segment by the average fully diluted NU common shares outstanding for the period. We use this measure to provide segmented earnings guidance and believe that this measurement is useful to investors to evaluate the actual financial performance and contribution of our business segments. This non-GAAP measure should not be considered as an alternative to our consolidated fully diluted EPS determined in accordance with GAAP as an indicator of our operating performance.

The discussion below also references our 2008 earnings and EPS excluding a significant charge associated with the settlement of litigation with Consolidated Edison, Inc. (Con Edison). We use these non-GAAP measures to more fully explain and compare the 2008 and 2007 results without including the impact of certain non-recurring items. Due to the nature and significance of the settlement charge, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to investors in analyzing historical and future performance. These measures should not be considered as alternatives to our reported net income or EPS determined in accordance with GAAP as indicators of our operating performance.

Reconciliations of above non-GAAP measures to respective GAAP measures of consolidated fully diluted EPS and net income are included under "-Financial Condition and Business Analysis-Overview-Consolidated" and "-Financial Condition and Business Analysis-Future Outlook."

FINANCIAL CONDITION AND BUSINESS ANALYSIS

Executive Summary

The following items in this executive summary are explained in more detail in this quarterly report:

Results, Strategy and Outlook:

.

We earned $57.8 million, or $0.37 per share, in the second quarter of 2008, compared with $48.5 million, or $0.31 per share, in the second quarter of 2007. The results in 2008 included regulated companies net income of $60.8 million, or $0.39 per share, after payment of preferred dividends, NU Enterprises, Inc. (NU Enterprises) net income of $2.2 million, or $0.01 per share, and NU parent and other companies net losses of $5.2 million, or $0.03 per share.

.

We earned $116.2 million, or $0.75 per share, in the first half of 2008, compared with $123.6 million, or $0.80 per share, in the first half of 2007. The 2008 results included regulated companies net income of $147.1 million, or $0.94 per share, after payment of preferred dividends, NU Enterprises net income of $4.1 million, or $0.03 per share, and NU parent and other companies net losses of $35 million, or $0.22 per share. The NU parent loss includes an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in the first half of 2008 were $146 million, or $0.94 per share.

.

Earnings at the distribution segments of The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH) (including regulated generation), Western Massachusetts Electric Company (WMECO) and Yankee Gas Services Company (Yankee Gas) totaled $25.6 million in the second quarter of 2008 and $79.4 million in the first half of 2008, compared with $23.4 million in the second quarter of 2007 and $71.6 million in the first half of 2007. These results reflect the fact that second quarter and first half 2008 electric sales were lower than sales in 2007 on an actual and weather normalized basis. Firm natural gas sales on an actual basis were also lower for the first half of 2008, but higher for the second quarter of 2008, as compared to sales in the same periods in 2007. Firm natural gas sales on a weather normalized basis were higher for the second quarter of 2008 and for the first half of 2008 as compared to sales in the same periods in 2007. Changes in electric sales have a lesser impact on earnings than in prior years due to current rate design, which recovers the majority of revenues through non-usage charges.

.

The transmission segments of CL&P, PSNH and WMECO earned $35.2 million in the second quarter of 2008 and $67.7 million in the first half of 2008, compared with $21.1 million in the second quarter of 2007 and $37 million in the first half of 2007.

.

CL&P continues to work on its three major transmission projects in southwest Connecticut. The Glenbrook Cables project is on schedule to be completed by the end of 2008, and the Middletown-Norwalk project is ahead of schedule and construction is currently expected to be completed in the first quarter of 2009. The Long Island Replacement Cable project was energized and placed into service on July 29, 2008. The Connecticut portion of the cable has been buried, however, the New York portion will be buried this fall in accordance with New York state permits. For more information on these projects, see "Business Development and Capital Expenditures - Regulated Companies - Transmission Segment" in this Management's Discussion and Analysis.

.

We now project consolidated 2008 earnings of between $1.60 per share and $1.75 per share, including the effect of the settlement with Con Edison, and between $1.80 per share and $1.95 per share excluding it. This projection represents an increase over prior guidance of $0.15 per share for the low-end of the range and $0.05 per share for the high end of the range.

Legal, Regulatory and Other Items:

.

On June 11, 2008, the Connecticut Department of Public Utility Control (DPUC) issued a final order pursuant to which Yankee Gas is required to refund to customers approximately $5.8 million in previous recoveries under Yankee Gas s Purchased Gas Adjustment (PGA) clause. The $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the second quarter 2008 earnings of Yankee Gas.

.

On June 25, 2008, the DPUC issued a final decision approving three proposed peaking generation units totaling 678 MW of summer peaking capacity and rejecting nine others, including both units that had been proposed by CL&P. In the third quarter of 2008, contracts for differences (CfDs) with the developers of the three approved units were signed or are expected to be signed by CL&P and UI, which were directed by the DPUC to share the net costs and benefits of the contracts on a basis of 80 percent and 20 percent, respectively.

.

On July 16, 2008, the Massachusetts Department of Public Utilities (DPU) issued a decision requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. WMECO is currently evaluating the timing of its next rate case.

.

On July 17, 2008, the Federal Energy Regulatory Commission (FERC) granted CL&P s request for a waiver of the provision of the FERC s March 24, 2008 order limiting its 100 basis point ROE adder solely to projects "completed and on line" by December 31, 2008 and approved the 100 basis point incentive for CL&P s entire Middletown-Norwalk transmission project. The FERC also granted an additional 50 basis point adder for the advanced technology aspects of the 24-mile underground portion of the project, which will be limited to 46 basis points based on the present overall ROE limit established by the FERC in the March 2008 order. We expect to increase our consolidated annual earnings beginning in 2009 by approximately $1 million once all the advanced technology equipment is in service.

Liquidity:

.

Our cash capital expenditures totaled $625.1 million in the first half of 2008, compared with $491.1 million in the first half of 2007. The increase in our cash capital expenditures was primarily the result of higher transmission segment capital expenditures, particularly at CL&P.

.

After giving effect to certain significant items impacting operating cash flows period over period, as discussed under "Liquidity - Consolidated" in this Management's Discussion and Analysis, cash flows provided by operations in the first half of 2008 were down slightly from the prior year. We continue to project that we will generate between $450 million and $500 million of cash flows from operations in 2008 after repayment of rate reduction bonds but before the net effect of the Con Edison settlement payment.

.

In the second quarter of 2008, NU parent, CL&P and PSNH issued a total of $660 million of long-term debt, which was used to repay short-term debt, to fund ongoing capital investment programs and for general working capital purposes. A portion of the $250 million received by NU parent from its debt issuance was also used to repay a $150 million long-term debt note that matured on June 1, 2008. As a result of these issuances, we had approximately $768 million of borrowing availability on our $900 million revolving credit lines as of June 30, 2008.

.

On June 30, 2008, CL&P terminated the arrangement under which a financial institution could purchase up to $100 million of CL&P s accounts receivable and unbilled revenues due to the availability and relative cost of other liquidity sources. We believe that we have sufficient liquidity without this arrangement.

<u>Overview</u>

Consolidated: We earned $57.8 million, or $0.37 per share, in the second quarter of 2008 and $116.2 million, or $0.75 per share, in the first half of 2008, compared with $48.5 million, or $0.31 per share, in the second quarter of 2007 and $123.6 million, or $0.80 per share, in the first half of 2007. Excluding an after-tax charge of $29.8 million, or $0.19 per share, associated with the settlement of litigation with Con Edison, our earnings in the first half of 2008 were $146 million, or $0.94 per share. A summary of our earnings by segment, which also reconciles consolidated net income and fully diluted EPS to the respective non-GAAP measures of consolidated non-GAAP earnings and EPS, as well as EPS by segment, for the second quarter and first half of 2008 and 2007, is as follows:

	For the Three Months Ended June 30,				**For the Six Months Ended June 30,**			
	2008		**2007**		**2008**		**2007**	
(Millions of Dollars, except per share amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income (GAAP)	$ 57.8	$ 0.37	$ 48.5	$ 0.31	$ 116.2	$ 0.75	$ 123.6	$ 0.80
Regulated companies	$ 60.8	$ 0.39	$ 44.5	$ 0.29	$ 147.1	$ 0.94	$ 108.6	$ 0.70
NU Enterprises	2.2	0.01	2.5	0.01	4.1	0.03	7.4	0.05
NU parent and other companies	(5.2)	(0.03)	1.5	0.01	(5.2)	(0.03)	7.6	0.05
Non-GAAP earnings	57.8	0.37	48.5	0.31	146.0	0.94	123.6	0.80
Con Edison litigation charge	-	-	-	-	(29.8)	(0.19)	-	-

Net Income (GAAP)	$	57.8	$	0.37	$	48.5	$	0.31	$	116.2	$	0.75	$	123.6	$	0.80

Regulated Companies: Our regulated companies, which consist of CL&P, PSNH, WMECO and Yankee Gas, segment their earnings between their electric transmission segment and their electric and gas distribution segments, with PSNH generation included with the electric distribution segment. A summary of regulated company earnings by segment for the second quarter and first half of 2008 and 2007 is as follows:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
(Millions of Dollars)		**2008**		**2007**		**2008**		**2007**
CL&P Transmission*	$	30.0	$	17.4	$	55.8	$	30.4
PSNH Transmission		3.6		2.6		8.8		4.5
WMECO Transmission		1.6		1.1		3.1		2.1
Total Transmission		35.2		21.1		67.7		37.0
CL&P Distribution*		14.8		7.0		33.7		27.6
PSNH Distribution and Generation		10.1		12.6		21.6		20.7
WMECO Distribution		1.7		3.5		6.5		9.4
Yankee Gas		(1.0)		0.3		17.6		13.9
Total Distribution and Generation		25.6		23.4		79.4		71.6
Net Income - Regulated Companies	$	60.8	$	44.5	$	147.1	$	108.6

*After preferred dividends in all periods.

The higher second quarter and first half 2008 transmission segment earnings reflect a higher level of investment in this segment as we continue to build out our transmission infrastructure to meet the region s reliability needs. CL&P s transmission earnings increased primarily due to CL&P s significant ongoing investment in projects in southwest Connecticut. The first half 2008 transmission segment results also included first quarter earnings of approximately $3.5 million associated with an order on rehearing issued by the FERC on March 24, 2008 concerning the ROE allowed to owners of New England electric transmission facilities, including CL&P, PSNH and WMECO.

CL&P s second quarter 2008 distribution segment earnings were $7.8 million higher than the same period in 2007 primarily due to higher distribution revenues resulting from the distribution rate increase effective February 1, 2008, and a lower effective income tax rate, partially offset by a 5.8 percent reduction in sales and higher operating costs.

For the first six months of 2008, CL&P s distribution segment earnings were $6.1 million higher than the same period in 2007 primarily due to higher distribution revenues, higher other revenues resulting from financial incentives under the 2005 "Act

Concerning Energy Independence" to promote distributed generation and demand side management, and a lower effective income tax rate. These items were partially offset by a 4 percent reduction in sales and higher operating costs. For the 12 months ended June 30, 2008, CL&P s distribution segment Regulatory ROE was 8.2 percent. We expect CL&P to achieve a distribution Regulatory ROE close to 8 percent in calendar year 2008.

PSNH s second quarter 2008 distribution and generation segment earnings were $2.5 million lower than the same period in 2007. PSNH s distribution and generation segment revenues increased as a result of distribution rate increases on July 1, 2007 and January 1, 2008, and a pre-tax adjustment to its generation segment cost recovery mechanism of $1.9 million, which were offset by a 1 percent decrease in sales and higher operating costs. The decrease in 2008 earnings was primarily due to the implementation of a retail transmission cost tracking mechanism in the second quarter of 2007 which provided for the recovery of $4.5 million of retail transmission costs that were expensed in 2006.

PSNH s distribution and generation segment earnings for the six months ended June 30, 2008 were slightly higher than the same period in 2007 primarily due to higher revenues as a result of distribution rate increases and a pre-tax adjustment to its generation segment cost recovery mechanism of $1.9 million, mostly offset by higher operating costs and the absence of the $4.5 million pre-tax benefit from the implementation of the retail transmission cost tracking mechanism in the second quarter of 2007. For the 12 months ended June 30, 2008, PSNH s combined distribution and generation segment Regulatory ROE was 8.8 percent. We expect PSNH to achieve a combined distribution and generation Regulatory ROE close to 9 percent in calendar year 2008.

WMECO s second quarter 2008 distribution segment earnings were $1.8 million lower than the same period in 2007, and for the first half of 2008, its distribution segment earnings were $2.9 million lower than the same period in 2007. The decline in earnings was primarily due to a $1.6 million pre-tax charge related to a DPU ruling on WMECO's 2005 and 2006 transition charge reconciliations, lower sales, and higher operating costs. For the 12 months ended June 30, 2008, WMECO s distribution segment Regulatory ROE was 8.2 percent. We expect WMECO to achieve a distribution Regulatory ROE close to 8 percent in calendar year 2008, which is lower than our previous expectation of between 9 percent and 9.5 percent. The decrease in the projected Regulatory ROE is primarily due to the DPU ruling on WMECO s 2005 and 2006 transition charge reconciliations, lower revenues and higher operating costs.

Yankee Gas s second quarter 2008 earnings were $1.3 million lower than the same period in 2007, primarily due to a DPUC order requiring Yankee Gas to refund $5.8 million of previous gas cost recoveries. This pre-tax charge was partially offset by higher revenues that resulted from a rate increase that took effect July 1, 2007. Yankee Gas s earnings for the first half of 2008 were $3.7 million higher than the same period in 2007, primarily due to higher revenues, partially offset by the refund described above and higher operating costs. Revenues were also impacted by a 2.6 percent decline in firm natural gas sales due primarily to warmer weather in the first quarter of 2008. For the 12 months ended June 30, 2008, Yankee Gas s Regulatory ROE was 9.1 percent. We expect Yankee Gas to achieve a Regulatory ROE close to 8 percent in calendar year 2008, which is lower than our previous expectation of between 9 percent and 9.5 percent. The decrease in the projected Regulatory ROE is primarily due to the DPUC's order requiring a refund of previous gas cost recoveries and increases in the cost of fuel inventories.

For the distribution segment of our regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric kilowatt-hour sales and Yankee Gas firm natural gas sales for the second quarter and first half of 2008 as compared to the same periods in 2007 on an actual and weather normalized basis (using a 30-year average) is as follows:

	For the Three Months Ended June 30, 2008 Compared to 2007							
	Electric							
	CL&P		PSNH		WMECO		Total	
	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	We Norr Perc (Dec Inc
Residential	(4.0)%	(3.3)%	(1.3)%	(0.3)%	(4.2)%	(3.4)%	(3.4)%	
Commercial	(3.8)%	(3.8)%	1.7 %	2.2 %	(0.7)%	(0.7)%	(2.3)%	
Industrial	(17.1)%	(17.0)%	(6.0)%	(5.7)%	(8.4)%	(8.5)%	(12.8)%	
Other	2.9 %	2.9 %	0.3 %	0.3 %	(7.1)%	(7.1)%	2.1 %	
Total	(5.8)%	(5.5)%	(1.0)%	(0.4)%	(3.8)%	(3.5)%	(4.5)%	

	For the Six Months Ended June 30, 2008 Compared to 2007							
	Electric							
	CL&P		PSNH		WMECO		Total	
	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Decrease	We Norr Perc Dec
Residential	(4.4)%	(3.3)%	(0.9)%	(0.3)%	(3.1)%	(2.1)%	(3.5)%	
Commercial	(1.3)%	(1.2)%	1.7 %	2.0 %	(0.5)%	(0.4)%	(0.6)%	
Industrial	(11.1)%	(11.1)%	(4.7)%	(4.5)%	(7.1)%	(7.1)%	(8.7)%	
Other	(4.8)%	(4.8)%	1.0 %	1.0 %	(3.3)%	(3.3)%	(4.3)%	
Total	(4.0)%	(3.5)%	(0.5)%	(0.1)%	(2.9)%	(2.5)%	(3.1)%	

A summary of our retail electric sales in gigawatt hours for CL&P, PSNH and WMECO and firm natural gas sales in million cubic feet for Yankee Gas for the second quarter and first half of 2008 and 2007 is as follows:

	For the Three Months Ended June 30,					
	Electric			Firm Natural Gas		
	2008	2007	Percentage (Decrease)/ Increase	2008	2007	Percentage (Decrease)/ Increase
Residential	3,126	3,237	(3.4)%	2,098	2,169	(3.3)%
Commercial	3,640	3,726	(2.3)%	2,127	2,170	(2.0)%
Industrial	1,291	1,481	(12.8)%	2,992	2,706	10.6 %
Other	76	74	2.1 %	-	-	0.0 %
Total	8,133	8,518	(4.5)%	7,217	7,045	2.4 %

	For the Six Months Ended June 30,					
	Electric			Firm Natural Gas		
	2008	2007	Percentage Decrease	2008	2007	Percentage (Decrease)/ Increase
Residential	7,111	7,372	(3.5)%	7,907	8,514	(7.1)%
Commercial	7,357	7,397	(0.6)%	7,577	7,904	(4.1)%

Industrial	2,525	2,767	(8.7)%	6,835	6,500	5.2 %
Other	167	175	(4.3)%	-	-	0.0 %
Total	17,160	17,711	(3.1)%	22,319	22,918	(2.6)%

Second quarter and first half 2008 actual and weather normalized electric sales were lower than sales in the same periods of 2007. The 2008 results reflect the fact that our customers are responding to the increasing costs of energy and the economic conditions of our region in different ways including the installation of distributed generation, utilization of conservation and load management programs, and the taking of steps to reduce their usage of electricity and reduce their usage in peak hours.

Changes in electric sales, however, have less of an impact on the earnings of the electric companies than in prior years because non-distribution revenues, which represent approximately 75 percent of electric company revenues, are tracked and reconciled to actual costs. Non-distribution revenues include the energy, stranded cost, retail transmission and federally mandated congestion cost (FMCC) charges and other components of rates. For non-distribution revenues, the only impact to earnings is from the carrying costs on over- or underrecoveries. Also, more than half of each of the electric company s distribution revenues is recovered through charges that are not dependent on overall sales volumes, such as the customer charge and demand charge.

In addition to the manner in which the distribution revenues are recovered from customers, there are other reasons why changes in 2008 sales have less of an impact on our earnings. For example, some of the decline in 2008 industrial sales was due to qualified distributed generation in Connecticut replacing our distribution. Under Connecticut statute, CL&P is entitled to recover this lost distribution revenue through its FMCC charge. Also, some of the decline in 2008 commercial sales was attributable to certain generators who, in previous periods, took station service from CL&P as retail commercial customers but now are served directly by ISO-NE as wholesale customers. These customers are interconnected to the transmission system and do not contribute to distribution revenues, therefore the loss of load from these customers in 2008 did not impact our earnings.

Overall, the pass-through nature of non-distribution revenues, the rate design of the distribution revenues and the lack of impact from the migration of station service sales combine to lessen the impact on earnings from reduced sales.

Firm natural gas sales on a weather normalized basis were higher in the second quarter and first half of 2008 when compared to sales in the same periods in 2007, but on an actual basis, sales for the first six months of 2008 were lower than sales in 2007 due to warmer weather in the first quarter of 2008. The majority of the increase in 2008 sales was in the industrial sector, and approximately half of the growth in industrial sales was due to the addition of customer-owned gas-fired distributed generation. Similar to our electric distribution companies, Yankee Gas would be entitled to recover over half of its revenues through non-usage charges if the DPUC approves its latest rate design proposal.

54

For the remainder of the year, we expect CL&P and PSNH weather normalized sales to be similar to the weather normalized sales for the first six months of 2008, but we believe weather normalized sales for WMECO could decline slightly. For Yankee Gas, we expect weather normalized sales to improve slightly.

Consistent with our sales results over the first half of 2008, our uncollectibles expense is also being influenced by the economic conditions of our region. Our write-offs as a percentage of revenues increased in 2008 for all our distribution companies, especially WMECO. As a result, our uncollectibles expense in the second quarter of 2008 was greater than expected, and our projected 2008 expense is somewhat higher than previously estimated. Similar to the changes in our retail sales, changes in our uncollectibles expense have less of an impact on the earnings of our distribution companies for a number of reasons. For example, a portion of the uncollectible expense for each of the electric distribution companies is allocated to its respective energy supply rate and recovered as a tracked expense. Additionally, for CL&P and Yankee Gas, write-offs attributable to hardship customers are tracked and fully recovered as authorized by statute. PSNH and WMECO offer discounts to limited income customers, and these discounts are also recovered.

NU Enterprises: NU Enterprises, which continues to manage to completion its remaining wholesale marketing contracts and energy services activities, earned $2.2 million in the second quarter of 2008 and $4.1 million in the first half of 2008, compared with $2.5 million in the second quarter of 2007 and $7.4 million in the first half of 2007. First half 2008 results include an after-tax reduction of earnings of $2.4 million associated with the implementation of SFAS No. 157, net of a $1.3 million benefit from partially reversing the SFAS No. 157 implementation charge as we served rather than exited Select Energy Inc.   s (Select Energy) wholesale marketing contracts in 2008. NU Enterprises' earnings for the second quarter of 2008 and 2007 included negative mark-to-market impacts of $1.4 million and $2.7 million, respectively, associated with the wholesale marketing contracts. NU Enterprises' earnings for the first half of 2008 and 2007 included negative mark-to-market impacts of $0.9 million and $1.2 million, respectively, associated with the wholesale marketing contracts.

NU Parent and Other Companies: NU parent and other companies lost $5.2 million in the second quarter of 2008 and $35 million in the first half of 2008, compared with earnings of $1.5 million in the second quarter of 2007 and $7.6 million in the first half of 2007. The 2008 first half loss results from the payment by NU parent to Con Edison of $49.5 million in March 2008 as part of a comprehensive settlement of litigation initiated in 2001 over the proposed but unconsummated merger between the two companies. The decrease in earnings from the second quarter and first half of 2007 was also the result of reduced interest income for NU parent on a significantly lower level of cash in 2008. NU parent carried a high level of cash in the first quarter of 2007 resulting from the sale of our competitive generation businesses on November 1, 2006. Most of that cash was either invested in the regulated companies in 2007 to support those companies   capital programs or used to pay taxes due in March 2007 on the competitive generation business sales.

Future Outlook

2008 Earnings Projection: We now project consolidated 2008 earnings of between $1.60 per share and $1.75 per share, including the effect of the settlement with Con Edison, and between $1.80 per share and $1.95 per share excluding it. A summary of our projected 2008 EPS by segment, which also reconciles consolidated fully diluted EPS to the non-GAAP measures of non-GAAP consolidated EPS and EPS by segment, is as follows:

	Previously Reported 2008 EPS Range				Revised 2008 EPS Range			
(Approximate amounts)		**Low**		**High**		**Low**		**High**
Fully Diluted EPS (GAAP)	$	1.45	$	1.70	$	1.60	$	1.75
Regulated companies:								
Distribution and generation segment	$	1.05	$	1.15	$	1.05	$	1.10
Transmission segment		0.75		0.85		0.85		0.90
Total regulated companies		1.80		2.00		1.90		2.00
NU Enterprises		-		-		-		0.05
NU parent and other companies (excluding Con Edison litigation charge)		(0.15)		(0.10)		(0.10)		(0.10)
Non-GAAP EPS		1.65		1.90		1.80		1.95
Con Edison litigation charge		(0.19)		(0.19)		(0.19)		(0.19)
Fully Diluted EPS (GAAP)	$	1.45	$	1.70	$	1.60	$	1.75

The 2008 earnings guidance for the regulated companies' transmission segment was raised due primarily to the companies' continued success in managing transmission projects and to the effects of the March 2008 FERC decision involving equity returns allowed on transmission projects. The distribution and generation segment guidance was narrowed due in part to lower sales in the first half of

2008 than previously projected. Additionally, we now estimate that our competitive businesses could earn better than our previous projection due to better than expected operating results in the first half of 2008. The loss projection for NU parent and other companies has also been narrowed, as interest costs are now projected to be lower than previously anticipated.

Long-Term Growth Rate: We continue to project that we can achieve an average compounded annual EPS growth rate of between 8 percent and 11 percent over 2007 earnings of $1.59 per share for the period 2008 through 2012. This EPS growth rate assumes achieved Regulatory ROEs of approximately 12 percent for transmission and between 9 percent to 10 percent for generation and distribution investments. This will require appropriate regulatory approvals and timely rate treatment associated with our electric transmission and distribution investments and natural gas distribution investments in a challenging environment of high energy prices. It also assumes we achieve our projected levels of capital expenditures and rate base growth in accordance with our present schedule.

Liquidity

Consolidated: In the second quarter of 2008, our liquidity position benefited from the issuance of a total of $660 million of long-term debt by NU parent, CL&P and PSNH. On June 5, 2008, NU parent sold $250 million of senior unsecured notes due June 1, 2013 and carrying a coupon of 5.65 percent. Most of the proceeds were used to repay a $150 million, 3.3 percent note that matured June 1, 2008. The balance of NU parent's debt issuance was used to pay down short-term debt, a portion of which was incurred in March 2008 as a result of the $49.5 million litigation settlement payment to Con Edison.

On May 27, 2008, CL&P sold $300 million of first and refunding mortgage bonds due May 1, 2018 and carrying a coupon of 5.65 percent. Also on May 27, 2008, PSNH sold $110 million of first mortgage bonds carrying a coupon of 6 percent and due May 1, 2018. Proceeds from the CL&P and PSNH issuances were used to repay short-term debt, to fund each company s ongoing capital investment programs, and for general working capital purposes. Along with these three debt issuances, Yankee Gas expects to issue up to $100 million of first mortgage bonds in the second half of 2008 primarily to repay short-term debt incurred in funding its capital investment program. This planned issuance was approved by the DPUC in July 2008.

We had $12.1 million of cash and cash equivalents on hand at June 30, 2008, compared with $15.1 million at December 31, 2007. We had operating cash flows of approximately $213 million, after rate reduction bond payments and excluding the settlement payment to Con Edison of $49.5 million, in the first half of 2008, compared with operating cash flows of approximately $253 million, after rate reduction bond payments and excluding tax payments of approximately $400 million related to the 2006 sale of the competitive generation business, in the first half of 2007. Other drivers resulting in decreased operating cash flows in 2008 from 2007 include a reduction from regulatory refunds and underrecoveries (net of income tax impacts) and a net reduction in other working capital items, offset by a benefit from counterparty deposits.

Excluding the $49.5 million Con Edison settlement payment, net of an expected $19.7 million reduction in income tax payments, we project consolidated operating cash flows of approximately $450 million to $500 million in 2008, after payments to retire our rate reduction bonds of approximately $231 million. This projection includes a potential net income tax settlement of approximately $70 million in the second half of 2008 and a reduction in income tax payments of $35 million over the remainder of the year related to bonus depreciation.

A summary of the current credit ratings and outlooks by Moody's Investors Service (Moody's), Standard & Poor's (S&P) and Fitch Ratings (Fitch) for NU parent and WMECO s senior unsecured debt and CL&P and PSNH's first mortgage bonds is as follows:

	Moody's		**S&P**		**Fitch**	
	Current	**Outlook**	**Current**	**Outlook**	**Current**	**Outlook**
NU Parent	Baa2	Stable	BBB-	Stable	BBB	Stable
CL&P	A3	Stable	BBB+	Stable	A-	Stable
PSNH	Baa1	Stable	BBB+	Stable	BBB+	Stable
WMECO	Baa2	Stable	BBB	Stable	BBB+	Stable

On July 29, 2008, Moody's changed the outlook of Yankee Gas to stable from negative and affirmed the company's Baa2 corporate credit rating.

If NU parent s senior unsecured debt ratings were to be reduced to a sub-investment grade level by either Moody's or S&P, a number of Select Energy's supply contracts would require Select Energy to post additional collateral in the form of cash or letters of credit (LOCs). Select Energy would, under its remaining contracts, be required to provide collateral or LOCs in the amount of $21.2 million to various unaffiliated counterparties and collateral or LOCs in the amount of $12 million to several independent system operators, in each case at June 30, 2008. If such a downgrade were to occur, NU parent would be able to provide that collateral.

NU parent paid common dividends of $62.6 million in the first half of 2008, compared with $58.5 million in the first half of 2007. The increase reflects a 6.7 percent increase in NU parent's common dividend that took effect in the third quarter of 2007. On May 12,

2008, our Board of Trustees approved a quarterly dividend of $0.2125 per share, a 6.25 percent increase over the previous dividend rate, payable on September 30, 2008 to shareholders of record as of September 1, 2008.

We expect to continue our current policy of dividend increases, subject to the approval of our Board of Trustees and to our future earnings and cash requirements. In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In the first half of 2008, CL&P, PSNH, WMECO and Yankee Gas paid $53.2 million, $18.2 million, $6.7 million, and $19 million, respectively, in common dividends to NU parent. In the first half of 2008, NU parent contributed $57.1 million of equity to CL&P, $35.5 million to PSNH, $16.3 million to WMECO, and $20.8 million to Yankee Gas.

NU parent's ability to pay dividends is not regulated under the Federal Power Act, but may be affected by certain state statutes, the leverage restrictions in its revolving credit agreement and the ability of its subsidiaries to pay dividends. Unless a higher amount is approved by the FERC, the Federal Power Act limits the payment of dividends by CL&P, PSNH and WMECO to their respective retained earnings balances, and PSNH is required to reserve an additional amount under its FERC hydroelectric license conditions. In addition, certain state statutes may impose additional limitations on the regulated companies. CL&P, PSNH, WMECO and Yankee Gas also are parties to a revolving credit agreement that imposes leverage restrictions.

Cash capital expenditures included on the accompanying condensed consolidated statements of cash flows and described in the liquidity section of this Management's Discussion and Analysis do not include amounts incurred on capital projects but not yet paid, cost of removal, the allowance for funds used during construction (AFUDC) related to equity funds, and the capitalized portion of pension expense or income. Our cash capital expenditures totaled $625.1 million in the first half of 2008, compared with $491.1 million in the first half of 2007. Our first half 2008 cash capital expenditures included $442 million by CL&P, $119.2 million by PSNH, $27.9 million by WMECO, $23.4 million by Yankee Gas and $12.6 million by other NU subsidiaries. The increase in our cash capital expenditures was primarily the result of higher transmission segment capital expenditures, particularly at CL&P.

NU Parent: NU parent maintains a credit line of $500 million that expires on November 6, 2010. At June 30, 2008, NU parent had $20 million of LOCs issued for the benefit of certain subsidiaries and $87 million of borrowings outstanding under that facility.

Regulated Companies: The regulated companies maintain a joint $400 million credit facility that expires on November 6, 2010. There were $45 million of long-term borrowings outstanding under that facility at June 30, 2008.

In addition to this revolving credit facility, CL&P had an arrangement with CL&P Receivables Corporation (CRC), a consolidated wholly-owned subsidiary of CL&P, and a financial institution under which the financial institution could purchase up to $100 million of CL&P's accounts receivable and unbilled revenues from CRC. On June 30, 2008, there were no receivables sold under that facility and CL&P chose to terminate the Receivables Purchase and Sale Agreement due to the availability and relative cost of other liquidity sources. At this time, we have no further plans to securitize the accounts receivable and unbilled revenues of our regulated companies and will utilize availability under our credit facilities and other financing vehicles, as necessary, to fund the daily operating activities and capital programs of these companies.

Borrowings under NU s credit facilities declined in the first half of 2008 as a result of the $660 million of long-term debt issuances noted above.

Impact of Credit Markets: Certain of CL&P's and PSNH's Pollution Control Revenue Bonds (PCRBs) carry bond insurance intended to enhance credit ratings. Certain bond insurers, including those insuring our PCRBs, have experienced increased pressure on ratings, with some ratings being reduced, and are on negative watch by the credit rating agencies. We do not expect the financial condition of our bond insurers to have a material impact on CL&P or PSNH, although concerns regarding the bond insurers' credit strength could increase interest expense associated with $151 million of PCRBs that we may remarket in 2008. PSNH has $89 million of insured PCRBs that have a variable rate that continues to be set in a 35-day auction. CL&P has $62 million of insured PCRBs with a fixed rate for a five-year period that expires October 1, 2008. Prior to that date, we will evaluate whether to change the interest rate mode on these bonds for future periods.

NU Enterprises: Most of the working capital and LOCs required by NU Enterprises are currently used to support Select Energy's remaining wholesale contracts. NU Enterprises' liquidity requirements are minimal.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income, totaled $658.4 million in the first half of 2008, compared with $531.3 million in the first half of 2007. Capital expenditures for the regulated companies are expected to total $1.3 billion in 2008, which includes $22 million related to our corporate service company and other affiliated companies that support the regulated companies. We expect to update our capital expenditure projections for 2009 through 2013 in November 2008.

Regulated Companies:

Transmission Segment: Transmission segment capital expenditures increased by $129 million in the first half of 2008 as compared with 2007 primarily due to expenditures at CL&P, which continues its significant enhancement of its transmission system in southwest Connecticut. We continue to project total capital expenditures for this segment in 2008 of approximately $700 million. However, due to changes in the timing of certain major transmission projects described below, we now expect to incur total transmission segment capital expenditures of approximately $350 million in 2009 instead of the previous projection of $506 million. At this time, we continue to project total transmission segment capital expenditures of $3 billion from 2008 through 2012.

A summary of transmission segment capital expenditures by company in the first half of 2008 and 2007 is as follows (millions of dollars):

	For the Six Months Ended June 30,	
	2008	**2007**
CL&P	$ 368.7	$ 267.4
PSNH	41.0	22.2
WMECO	15.6	7.1
HWP	1.0	0.6
Totals	$ 426.3	$ 297.3

CL&P has three major transmission projects currently under construction in southwest Connecticut. They are:

.

A 69-mile, 345 kilovolt (KV)/115 KV transmission project from Middletown to Norwalk, Connecticut (Middletown-Norwalk). CL&P's portion of this project was estimated to cost approximately $1.05 billion. Originally due to be in service by the end of 2009, construction is currently expected to be complete by the first quarter of 2009. We expect the 45-mile overhead section of the project to be completed and in service by the end of 2008 and the 24-mile underground section to be substantially complete by the end of 2008 and in service in the first quarter of 2009. We now expect the project to be completed at a total cost of approximately $1 billion, approximately $50 million below our earlier estimate. As of July 31, 2008, CL&P's portion of this project was 95 percent complete. As of June 30, 2008, CL&P had capitalized $817 million associated with this project and placed $274 million into service.

.

A two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), construction of which began in October 2006. This project is estimated to cost approximately $223 million and is scheduled to be completed by the end of 2008. As of July 31, 2008, this project was 93 percent complete. As of June 30, 2008, CL&P had capitalized $206 million associated with this project and placed $26 million into service.

.

The replacement of the 138 KV, 11-mile undersea electric transmission cable between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable). CL&P and the Long Island Power Authority (LIPA) each own approximately 50 percent of the line. CL&P's portion of the project is estimated to cost $72 million. On July 18, 2008, the New York Public Service Commission approved LIPA's request to energize the Long Island Replacement Cable. The project was placed into service on July 29, 2008, ahead of the previously anticipated in-service date of October 2008. The Connecticut portion of the cable has been buried, however, the New York portion will be buried this fall in accordance with New York state permits. As of June 30, 2008, CL&P had capitalized $67 million associated with this project and placed $4 million into service.

In addition to our current transmission construction in southwest Connecticut, we continue to work with the New England Independent System Operator (ISO-NE) to refine the design for our next series of major transmission projects, the New England East-West Solutions (NEEWS). That series of projects involves our construction of new overhead 345 KV lines in Massachusetts and Connecticut as well as associated substation work and 115 KV rebuilds. One of the projects will connect to a new transmission line that National Grid plans to build in Rhode Island. On May 19, 2008, National Grid and NU presented the ISO-NE Planning Advisory Committee with recommended options for building the NEEWS projects, with formal approval expected by the end of this year. We estimate that these recommended options will involve approximately $1.49 billion of capital spending by CL&P and WMECO through 2013.

The first of these, the Greater Springfield Reliability Project, is the largest and most complicated project within NEEWS. In May 2008, we modified that project by incorporating key elements of our previously planned 115 KV Springfield Underground Cables Project. The revised Greater Springfield Reliability Project is expected to cost approximately $714 million if built according to our preferred route and configuration. Municipal consultations began in late June 2008, and we expect CL&P and WMECO to file siting applications with Connecticut and Massachusetts regulators in September 2008. If approved as expected in 2010, we expect to commence construction in late 2010 and place the project in service by mid-2013.

Our second major project of NEEWS is the Interstate Reliability Project, which is being designed and built in coordination with National Grid. NU's share of this project includes a 40-mile 345 KV line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid is designing. We expect NU's share of this project to cost approximately $250 million, and CL&P plans to file siting applications with Connecticut by the end of 2008 with construction beginning in 2010. We expect the project to be placed in service as early as late 2012.

The third part of NEEWS is the Central Connecticut Reliability Project, which involves construction of a new line from Bloomfield, Connecticut to Watertown, Connecticut. This line would provide us with another 345 KV connection to move power into southwest Connecticut, where approximately half of the state s electricity is consumed. The timing of this project would be six to twelve months behind the other two projects, and CL&P expects to initiate the siting process in mid-2009 with construction beginning in 2011. The project is expected to be placed in service in 2013 with a cost of approximately $315 million.

Included as part of NEEWS are approximately $210 million of reliability related expenditures, many of which may be incurred in advance of the three major projects. CL&P and WMECO expect to begin filing siting applications related to some of these expenditures later in 2008.

During the siting approval process, state regulators may require changes in configuration to address local concerns which could increase construction costs. Our current design for NEEWS does not contemplate any underground 345 KV lines. Building 345 KV lines underground would increase total costs, and our estimate could be increased during the siting approval process.

Distribution and Generation Segment: We now project a total of approximately $541 million of distribution and generation segment capital expenditures for 2008. A summary of these estimated capital expenditures for the regulated companies distribution and generation segments by company for 2008 is as follows (millions of dollars):

CL&P	$	299
PSNH		167
WMECO		35
Yankee Gas		40
Totals	$	541

On February 15, 2008, Yankee Gas and NRG Energy, Inc. entered into a settlement agreement, which among other things, enabled the recovery of approximately $17.5 million of capital costs and expenses incurred by Yankee Gas related to an NRG subsidiary's generating plant construction project that has ceased. The previously reported Yankee Gas capital expenditures projection for 2008 decreased from $56 million to approximately $40 million primarily as a result of the accounting adjustment recorded in the first half of 2008 related to the settlement agreement.

A summary of distribution and generation segment capital expenditures by company in the first half of 2008 and 2007 is as follows (millions of dollars):

	For the Six Months Ended June 30,			
	2008		2007	
CL&P	$	131.6	$	128.0
PSNH		69.4		56.3
WMECO		15.9		16.4
Yankee Gas		6.2		29.1
Other		0.3		0.1
Totals	$	223.4	$	229.9

The first half of 2008 capital expenditures at Yankee Gas were reduced by the $17.5 million accounting adjustment described above, while the first half of 2007 capital expenditures included $9.3 million spent on its $108 million liquefied natural gas (LNG) storage and production facility in Waterbury, Connecticut, which was placed in service in July 2007.

As mandated by New Hampshire statute, PSNH plans to install a wet scrubber at its coal-fired, two-unit base load Merrimack plant in Bow, New Hampshire (Clean Air Project). PSNH now estimates that the Clean Air Project will cost approximately $457 million, compared with its initial estimate of $250 million, which will be recovered through PSNH generation rates under the statute. This revised estimate includes significant increases in the prices for materials, construction services and engineering services required to design and build the scrubber and associated plant. The Clean Air Project is expected to reduce the two units mercury emissions by approximately 85 percent and sulfur dioxide emissions by more than 90 percent, as well as allow PSNH to avoid the purchase of 30,000 sulfur dioxide credits required to be purchased annually. PSNH expects to start construction on this project in 2009, and under

New Hampshire statute, the scrubber must be operational by July 2013. The first half of 2008 capital expenditures at PSNH include $5.8 million in costs related to this project.

Strategic Initiatives: We are evaluating certain development projects that would benefit our customers, such as new regulated generating facilities, investments in wide-spread advanced metering infrastructure (AMI) systems, and transmission projects to better interconnect new renewable generation in northern New England and Canada with southern New England, as well as interconnections within New Hampshire. The estimated capital expenditures discussed above do not include expenditures related to any of these strategic initiatives.

Among the projects we are evaluating is construction of new transmission upgrades in northern New Hampshire to support the addition of 400 MW of new renewable generation (including potential wind and biomass generation), along with other upgrades to the New England transmission system. As our next step in the process of identifying potential solutions to the region s energy and environmental needs, on March 31, 2008, we filed a formal request with ISO-NE to analyze potential increases in the North-South high voltage power transfer capacity from New Hampshire into Massachusetts to deliver additional power from renewable and low-carbon emitting resources in northern New England and Canada to southern New England. We requested that ISO-NE analyze the best methods of increasing that capability by 1,500 MW to 2,500 MW. We expect the economic study of some of the above initiatives by ISO-NE to be completed in 2009.

Transmission Rate Matters and FERC Regulatory Issues

CL&P, PSNH and WMECO and most other New England utilities, generation owners and marketers are parties to a series of agreements that provide for coordinated planning and operation of the region's generation and transmission facilities and the market rules by which these parties participate in the wholesale markets and acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent from all market participants, has served as the Regional Transmission Organization (RTO) for New England since February 1, 2005. ISO-NE works to ensure the reliability of the New England transmission system, administers the independent system operator tariff (ISO Tariff), subject to FERC approval, oversees the efficient and competitive functioning of the regional wholesale power market and determines which portion of the costs of our major transmission facilities are regionalized throughout New England.

Transmission - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under the ISO-NE FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes RNS and LNS rate schedules to recover fees for transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, which we administer, is reset on January

1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining three southwest Connecticut projects (Middletown-Norwalk, Glenbrook Cables and Long Island Replacement Cable). The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that we recover all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to customers. In the second quarter of 2008, under the terms of Tariff No. 3, NU recovered $23 million of the 2007 underrecovery and deferred an underrecovery of $21 million for differences in the second quarter of 2008. As of June 30, 2008, the LNS rates were in a total underrecovery position of approximately $34 million, which will fluctuate period to period. On June 1, 2008, the RNS rate and LNS rate were increased to reflect true-ups for historical costs and to reflect forecasted capital expenditures. We believe that these rates will provide us with timely recovery of transmission costs, including costs of our major transmission projects.

FERC ROE Decision: As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (Initial ROE Order), we recorded an estimated regulatory liability for refunds in 2006. In 2007, we completed the customer refunds that were calculated in accordance with the compliance filing required by the Initial ROE Order, and refunded amounts to regional, local and localized transmission customers.

On March 24, 2008, the FERC issued an order on rehearing of its Initial ROE Order. In the rehearing order, the FERC, among other things, increased the base ROE on transmission projects for the transmission owners from the 10.2 percent allowed in the Initial ROE Order to 10.4 percent effective February 1, 2005 and reaffirmed its Initial ROE Order increasing the ROE by 74 basis points for the period beginning November 1, 2006 in recognition of higher bond yields. The rehearing order also modified the FERC's Initial ROE Order provision allowing 100 additional basis points for new transmission projects that are built as part of the ISO-NE RSP by limiting the 100 basis points adder solely to projects that are "completed and on line" by December 31, 2008. In order to receive incentives for projects completed after December 31, 2008, the rehearing order requires transmission owners to file with the FERC project-specific requests that meet the nexus requirements under FERC guidelines. In addition, while not an issue in this rehearing, the provision of the Initial ROE Order increasing the ROE by 50 additional basis points for New England transmission owners joining an RTO and giving the RTO operational control of the transmission owner s transmission facilities was left unchanged. In the first quarter of 2008, we recognized $3.5 million in transmission segment earnings related to this order, of which approximately $2.9 million related to the February 1, 2005 through December 31, 2007 time period. This order has been appealed to the D.C. Circuit Court of Appeals by various state regulators.

On June 12, 2008, the New England Conference of Public Utility Commissioners (NECPUC) filed a complaint at the FERC against all of the New England Transmission Owners, including us, seeking to limit the application of the 100 basis point ROE adder to the original transmission project cost estimates in the 2004 ISO-NE Regional Transmission Expansion Planning process. There is no specific deadline for the FERC to act on a complaint, but responses from all of the New England Transmission Owners have been filed at the FERC.

On May 16, 2008, we filed an application on behalf of CL&P with the FERC to receive return on equity incentives for CL&P s Middletown-Norwalk project. The 45-mile 345 KV overhead sections are expected to be in service by the end of 2008 while the 24-mile 345 KV underground sections are expected to be in service in the first quarter of 2009. On July 17, 2008, the FERC granted a waiver of the December 31, 2008 "completed and on line" date for a 100 basis point ROE adder and approved the 100 basis point incentive for the entire Middletown-Norwalk project. The FERC also granted an additional 50 basis point adder for the advanced technology aspects of the 24-mile underground portion of the project. The 50 basis point adder will be limited to 46 basis points based on the present overall ROE limit established by the FERC, resulting in a total ROE for the underground portion of the Middletown-Norwalk project of 13.1 percent. The cost of the underground portion is estimated to be slightly less than half of CL&P's overall $1.05 billion cost. Once all advanced technology equipment is in service, the technology adder will increase our consolidated annual earnings beginning in 2009 by approximately $1 million. Parties have 30 days from the date of this order to seek a rehearing with the FERC.

We also expect to file with the FERC for incentives on each of our other major transmission projects that are completed after December 31, 2008, including our full investment in the NEEWS projects. Assuming these projects receive the incentives, we expect the projected overall blended ROE in our transmission segment to increase to approximately 12 percent in 2008 and 2009, rising to approximately 12.1 percent in 2010 through 2013.

Legislative Matters

Environmental Legislation: RGGI is a voluntary effort by certain northeastern states, including Connecticut, New Hampshire and Massachusetts, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fuel-fired electric generators. The initiative proposes to stabilize CO_2 emissions at current levels and requires a 10 percent reduction by 2018 from the initial 2009 permitted levels. Each signatory state committed to propose for approval the legislative and regulatory mechanisms necessary to implement the program. The first regional auction of

RGGI credits is scheduled for September 2008, though some states may not be ready to participate in this auction.

Connecticut Connecticut adopted regulations in July 2008 which establish a clearing price threshold of $5 per ton, above which all auction proceeds are rebated to customers. Connecticut has been allocated approximately 11 million annual credits under the RGGI program. For revenues up to the clearing price threshold, 69.5 percent will be directed to the conservation and load management programs managed by the state s utilities in conjunction with the Energy Conservation Management Board. CL&P s share of the RGGI funds will be 75 percent of the directed funds.

New Hampshire Legislation signed by New Hampshire Governor Lynch in June 2008 provides up to a 2.5 million banked-allowance allocation per year for fossil fueled generating plants owned and operated by PSNH during the first three-year compliance period. PSNH anticipates that this allocation will make up approximately one-half of the credits necessary for its generating plants to comply with RGGI. PSNH will purchase the additional required credits from quarterly RGGI auctions. New Hampshire has been allocated approximately 9 million annual credits under the RGGI program. Additionally, the law sets a clearing price threshold of $6 per ton in 2009, above which all auction proceeds will be rebated to customers. The law requires that proceeds below the threshold are to be used for demand response and energy efficiency programs.

Massachusetts Legislation signed by Massachusetts Governor Patrick in July 2008 did not set a clearing price threshold on auction levels. This act requires that 80 percent of RGGI auction proceeds be allocated to utility energy efficiency and demand response programs. Allocation and distribution of these funds will be decided by a newly created Energy Efficiency Council. Utilities are required to file a 3-year energy efficiency plan by April 30, 2009. Massachusetts has been allocated approximately 26 million annual credits under the RGGI program.

New Hampshire:

2008 Legislation: In July 2008, New Hampshire Governor Lynch signed into law a bill establishing a transmission commission responsible for developing a proposal to expand the electric transmission system in northern New Hampshire to encourage the development of new renewable generation sources. The transmission commission must finalize its proposal by December 1, 2008. In 2007, the New Hampshire Public Utilities Commission (NHPUC) had forwarded to the legislature a study that indicated that it would cost approximately $200 million to upgrade northern New Hampshire transmission capacity to support the addition of 300 MW of wind generation and 100 MW of biomass generation. PSNH is currently evaluating building new transmission upgrades in northern New Hampshire to support the addition of 400 MW of renewable generation in the area.

On July 11, 2008, New Hampshire Governor Lynch signed into law a bill authorizing rate recovery by electric public utilities of investments made in distributed energy resources, such as renewable energy generation. The total investment is limited to 6 percent of a distribution utility s peak load. We have not yet included any investment opportunities for PSNH in our capital expenditure plans.

Massachusetts:

2008 Legislation: As described above, on July 2, 2008, Massachusetts Governor Patrick signed into law a comprehensive energy law called "The Green Communities Act of 2007." Aimed at increasing energy efficiency (EE) and the use of renewable resources in the state, the Act contains many provisions important to the state s utilities. Among other things, the Act:

.

Adopts RGGI for MA and requires that 80 percent of RGGI auction proceeds be earmarked for EE and demand response (DR);

.

Removes the cap on utility expenditures for EE and DR. Requires utilities to file three-year EE and DR plans with a newly created Energy Efficiency Council;

.

Requires utilities to sign long-term contracts for renewable resources;

.

Allows utilities to own and operate up to 50 MW of solar generation;

.

Requires utilities to file a plan with the DPU for a smart grid pilot; and

.

Increases penalties for failure to meet service quality standards from 2 percent of transmission and distribution revenues to 2.5 percent.

By April 30, 2009, WMECO will prepare a three-year EE and DR investment plan related to the cost of EE and DR programs established by the Act for review by a new Energy Efficiency Council and, ultimately, the DPU. We have not yet included any investment opportunities for WMECO in our capital expenditure plan.

Regulatory Developments and Rate Matters

Regulated Electric Distribution Companies: We are currently evaluating the rate case strategy of our electric distribution companies. Based on each company s earnings, cost trends and sales trends in 2008, as well as the rate decoupling decision in Massachusetts described below, it is probable that CL&P, PSNH and WMECO will file distribution rate cases in 2009.

Regulated Companies Transmission Revenues - Retail Rates: A significant portion of our transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. Each of these companies has a retail transmission cost tracking mechanism as part of their rates, which allows them to charge their retail customers for transmission costs on a timely basis.

Connecticut - CL&P:

Peaking Generation Filing: In 2007, Connecticut Governor Rell signed into law "An Act Concerning Electricity and Energy Efficiency" (Energy Efficiency Act). On March 3, 2008, as required by the DPUC under the Energy Efficiency Act, CL&P filed a proposal with the DPUC to build a total of 265 MW of peaking generation. On June 25, 2008, the DPUC issued a final decision approving three proposed units totaling 678 MW of summer peaking capacity and rejecting nine others, including the two units proposed by CL&P. CfDs with the developers of the three approved units were signed or are expected to be signed by CL&P and UI in the third quarter of 2008. As directed by the DPUC, CL&P and UI have entered into a sharing agreement relating to the three CfDs, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of the contracts. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P customers.

Renewable Energy Contracts: In May 2008, pursuant to Connecticut's "Act Concerning Energy Independence," (Energy Independence Act), CL&P signed five contracts and UI signed one contract to purchase energy, capacity and renewable energy credits from planned renewable energy plants, including biomass and fuel cell projects approved by the DPUC in January 2008.

Purchases under the contracts are scheduled to begin in 2008 through 2011 and range from periods of 15 to 20 years. As directed by the DPUC, CL&P and UI have also signed a sharing agreement under which they will share the costs and benefits of these contracts, with 80 percent to CL&P and 20 percent to UI. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers. A third round of projects for an additional 26 MW of renewable energy generation is being reviewed by the DPUC for selection in January 2009.

FMCC Filing: On February 5, 2008, CL&P filed with the DPUC its semi-annual reconciliation to document actual FMCC charges (including Energy Independence Act charges), GSC revenues and expenses and Energy Adjustment Clause (EAC) charges for the period July 1, 2007 through December 31, 2007. This filing also contained CL&P's revenue and cost information for the period January 1, 2007 through June 30, 2007, for which the DPUC previously approved all costs as filed in its final decision issued January 23, 2008. This filing identified overrecoveries totaling approximately $105 million for the full year 2007, of which approximately $88 million was reflected in the annual CL&P rate change effective January 1, 2008, and an additional approximately $1 million was reflected in CL&P's Last Resort Service (LRS) rate change effective April 1, 2008. Therefore, there is a net remaining overrecovery of approximately $16 million from 2007 which, effective July 1, 2008, is being refunded to customers over a six-month period. A decision on CL&P's semi-annual reconciliation filing is expected to be issued in August 2008.

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under Standard Service (SS) rates, and large commercial and industrial customers who do not choose competitive suppliers are served under LRS rates. Effective July 1, 2008, the DPUC approved an increase to CL&P's total average SS and LRS rates of approximately 4.9 percent and 33.2 percent, respectively. The new LRS rate will remain in effect until September 30, 2008, while the new SS rate will remain in effect until December 31, 2008. The energy supply portion of the total average SS and LRS rates increased from 11.762 cents per KWH to 11.852 cents per KWH and from 10.466 cents per KWH to 14.559 cents per KWH, respectively. CL&P is fully and timely recovering the costs of its SS and LRS services.

Transmission Adjustment Clause: On June 16, 2008, CL&P filed a transmission adjustment clause (TAC) with the DPUC requesting an increase in its retail transmission rate effective July 1, 2008 to collect $67.9 million of additional revenues over the second half of the year. The increase in the TAC was attributable to the ongoing investment in regional transmission reliability projects. The DPUC approved CL&P's filing on June 25, 2008.

Customer Service Docket: On June 19, 2008, the DPUC issued a draft order in a docket investigating CL&P billing errors involving approximately 2,000 customers on time of use rates. The draft decision found that CL&P had appropriately believed that the correct software changes would be made in time to incorporate new rate structures and rates effective January 1, 2008, but that its actions and communications both internally and externally after it found that the bills were not being accurately calculated were imprudent. The draft order determined that CL&P was liable for costs associated with the billing errors, which have been expensed as incurred. A final decision by the DPUC is due in August 2008.

Connecticut - Yankee Gas:

Purchased Gas Adjustment: In 2005 and 2006, the DPUC issued decisions regarding Yankee Gas s PGA clause charges and required an audit of previously recovered PGA revenues of approximately $11 million associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund approximately $5.8 million in previous recoveries to its customers. The $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the second quarter 2008 earnings of Yankee Gas.

New Hampshire:

Delivery Service Rates: On July 1, 2008, PSNH s distribution rates decreased by approximately $0.4 million annually. This amount consisted of a $3.4 million rate reduction related to the full recovery of a rate differential recoupment and an annual increase of $3 million for additional funding of the major storm reserve for a two-year period.

The rate differential recoupment was effected pursuant to the NHPUC May 2007 approval of PSNH s distribution and transmission rate case settlement agreement between PSNH, the NHPUC staff and the New Hampshire Office of Consumer Advocate. It represents the difference between temporary distribution rates previously allowed and permanent distribution rates ultimately approved by the NHPUC and implemented effective July 1, 2007.

The $3 million additional funding of the major storm reserve was effected pursuant to a rate order issued June 27, 2008 in which the NHPUC accepted PSNH's proposal to increase its distribution rates by approximately $3 million for a two-year period effective July 1, 2008 to eliminate the current negative balance in the major storm reserve and restore the intended reserve level of $1 million. As part of its review of the PSNH proposal, the NHPUC began an audit of all major storm costs accrued to the major storm reserve and the order states that any adjustments resulting from the major storm reserve audit will be dealt with through future proceedings or as adjustments to the existing major storm reserve balance.

ES and SCRC Rates: On June 27, 2008, the NHPUC issued orders increasing the default energy service (ES) rate from 8.82 cents per KWH to 9.57 cents per KWH and lowering the stranded cost recovery charge (SCRC) rate from 0.72 cents per KWH to 0.65 cents per KWH effective on July 1, 2008. The increase in the ES rate is attributable to an increase in overall energy market prices which results in higher fuel and purchased power costs for 2008, as compared to 2007. The decrease in the SCRC rate is primarily a result of lower over-market Independent Power Producer (IPP) related costs.

TCAM Reconciliation and Rates: On May 13, 2008, PSNH filed a July 1, 2007 through June 30, 2008 transmission cost adjustment mechanism (TCAM) reconciliation and a projected TCAM rate to be billed effective July 1, 2008 related to July 1, 2008 through June 30, 2009 TCAM cost estimates. Under the terms of an NHPUC rate order issued on June 27, 2008, PSNH s TCAM rate was increased from 0.752 cents per KWH to 0.935 cents per KWH, effective July 1, 2008.

Renewable Portfolio Standards: On May 11, 2007, New Hampshire Governor Lynch signed into law the "Renewable Energy Act," establishing renewable portfolio standards (RPS) that requires annual increases in the percentage of electricity with direct ties to renewable sources sold to New Hampshire retail customers. The renewable sourcing requirements begin in 2008 and increase each year to reach 23.8 percent by 2025.

PSNH plans to meet these standards, in part, through the purchase of renewable energy certificates (RECs) from a qualified renewable energy resource. For each MWH of energy produced from a qualifying renewable resource, the producer will receive one REC. Energy suppliers, like PSNH, will purchase these RECs from the producers and will use them to satisfy the RPS requirements. To the extent that PSNH is unable to purchase sufficient RECs, it will be required to make up the difference between the RECs purchased and its total obligation by making an alternative compliance payment (ACP) for each REC requirement for which PSNH is deficient. The costs of both the RECs and ACPs will not directly impact earnings, as these costs will be recovered by PSNH through its ES rates.

Massachusetts:

Decoupling Decision: On July 16, 2008, the DPU issued a decision in its decoupling generic docket requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. The decision rejected calls for partial decoupling or decoupling by rate design in favor of full decoupling by rate class. Actual revenues are to be reconciled to target revenues, as established in litigated rate cases, on an annual basis. Adjustments per the reconciliation will be made to the distribution component of rates. The decision also determined that the DPU will honor existing long-term rate plans, performance-based regulation plans and settlements, but all utilities must file notices with the DPU by September 2, 2008 disclosing when they intend to file their next rate case.

Basic Service Rates: Effective July 1, 2008, the rates for basic service customers increased due to the rise in the cost of energy, which was reflected in WMECO's most recent basic service solicitations. Basic service rates for residential and small commercial and industrial customers increased from 10.8 cents per KWH to 12.1 cents per KWH, and rates for medium and large commercial and industrial customers increased from 10.5 cents per KWH to 14.6 cents per KWH.

Contingent Matters:

The items summarized below contain contingencies that may have an impact on our net income, financial position or cash flows. See Note 5A, "Commitments and Contingencies - Regulatory Developments and Rate Matters," to the condensed consolidated financial statements for further information regarding these matters.

.

CTA and SBC Reconciliation: On March 31, 2008, CL&P filed with the DPUC its 2007 Competitive Transition Assessment (CTA) and System Benefits Charge (SBC) reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million, which has been recorded as a decrease to the CTA regulatory asset on the accompanying condensed consolidated balance sheets. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million, which has been recorded as a regulatory asset on the accompanying condensed consolidated balance sheets. We expect a decision from the DPUC on this docket by the end of 2008 and do not expect the outcome to have a material adverse impact on CL&P's net income, financial position or cash flows.

.

Procurement Fee Rate Proceedings: CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its procurement fee, which was effective through 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. CL&P has not recorded amounts related to the 2005 or 2006 procurement fee in earnings, although we estimate that if CL&P s methodology is upheld, CL&P would record in 2008 after-tax amounts of $3.3 million for 2006 and $3.6 million for 2005.

CL&P has recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. If the DPUC does not allow recovery of $5.8 million for procurement fees in its final decision, then CL&P would record a loss and establish an obligation to refund this amount to its customers. A date for the new draft decision in this docket has not yet been determined by the DPUC. We believe that final regulatory approval of the $5.8 million pre-tax amount is probable.

.

ES and SCRC Reconciliation: On May 1, 2008, PSNH filed its 2007 ES/SCRC reconciliation with the NHPUC. Hearings are scheduled before the NHPUC in November 2008. We do not expect the outcome of the NHPUC's review of this filing to have a material adverse impact on PSNH's net income, financial position or cash flows.

.

Transition Cost Reconciliations: On July 18, 2008, WMECO filed its 2007 transition cost reconciliation with the DPU. The schedule for reviewing this filing will be set by the DPU at a later date. We do not expect the outcome of the DPU's review of this filing to have a material adverse effect on WMECO's net income, financial position or cash flows.

<u>NU Enterprises Divestitures</u>

We have exited most of our competitive businesses. NU Enterprises continues to manage to completion its remaining wholesale marketing contracts and energy services activities.

Wholesale Marketing: In the first half of 2008, Select Energy continued to manage its remaining PJM power pool wholesale sales contract and its related supply contracts, which expired on May 31, 2008, and its long-term wholesale sales contract with the New York Municipal Power Agency (NYMPA), an agency comprised of municipalities, and related supply contracts, that expires in 2013. These contracts are derivatives that have been marked to market through earnings. In addition to the NYMPA-related contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to purchase the output of a certain generating facility in New England through 2012. As a non-derivative contract, the fair value of the contract has not been reflected on the balance sheet, and the contract has not been marked to market. Based on the current estimated value of this non-derivative contract, when combined with the fair value of the derivative contracts in the NYMPA portfolio and cash collateral balances at June 30, 2008, we believe, under present conditions, that the estimated total net cash cost at June 30, 2008 to exit the remaining wholesale contracts if served out or settled at the same time is approximately break-even.

Energy Services: Most of NU Enterprises' energy services businesses were sold in 2005 and 2006. Certain other businesses were wound down in 2007. We continue to own and manage E.S. Boulos Company.

In connection with the sale of the retail marketing business, the competitive generation business and certain of the energy services businesses, we provided various guarantees and indemnifications to the purchasers of those businesses. See Note 5D, "Commitments and Contingencies - Guarantees and Indemnifications," to the condensed consolidated financial statements for information regarding these items.

NU Enterprises Contracts

Wholesale Derivative Contracts: On January 1, 2008, we implemented SFAS No. 157. For further information on SFAS No. 157, see Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 3, "Fair Value Measurements," to the condensed consolidated financial statements, and the "Critical Accounting Policies and Estimates Update" section of this Management s Discussion and Analysis.

At June 30, 2008 and December 31, 2007, the fair value of NU Enterprises' wholesale derivative assets and derivative liabilities (through its subsidiary Select Energy), which are subject to mark-to-market accounting, are as follows:

(Millions of Dollars)		**June 30, 2008**		**December 31, 2007**
Current wholesale derivative assets	$	22.1	$	36.2
Long-term wholesale derivative assets		22.5		7.2
Current wholesale derivative liabilities		(33.7)		(64.9)
Long-term wholesale derivative liabilities		(85.5)		(72.5)
Portfolio position	$	(74.6)	$	(94.0)

Numerous factors could either positively or negatively affect the realization of the wholesale derivative net fair value amounts in cash. These factors include the volatility of commodity prices until the derivative contracts are exited or expire, differences between expected and actual volumes, the performance of counterparties, and other factors.

Select Energy has policies and procedures requiring all of its wholesale derivative energy positions to be valued daily and segregating responsibilities between the individuals actually transacting (front office) and those confirming the trades (middle office). The middle office is responsible for determining the portfolio's fair value independent from the front office.

The methods Select Energy used to determine the fair value of its wholesale derivative contracts are identified and segregated in the table of fair value of wholesale derivative contracts at June 30, 2008 and December 31, 2007. A description of each method is as follows: 1) prices actively quoted primarily represent New York Mercantile Exchange (NYMEX) futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards and options, including bilateral contracts for the purchase or sale of electricity, and are marked to the mid-point of bid and ask market prices. The mid-points of market prices are adjusted to include all applicable market information, such as prior contract settlements with third parties and bilateral contract prices in illiquid periods. Currently, Select Energy also has a derivative contract for which a portion of the contract's fair value is determined based on a model. The model utilizes natural gas prices and a conversion factor to electricity for off-peak periods in 2012 and all periods for 2013. Broker quotes for electricity, at locations for which Select Energy has entered into transactions, are generally available through 2011 for on-peak and off-peak periods and through 2012 for on-peak periods.

Generally, valuations of short-term derivative contracts derived from quotes or other external sources are more reliable should there be a need to liquidate the contracts, while valuations for longer-term derivative contracts are less certain. Accordingly, there is a risk that derivative contracts will not be realized at the amounts recorded.

The tables below disaggregate the estimated fair value of the wholesale derivative contracts. Valuations of individual contracts are broken into their component parts based upon prices actively quoted, prices provided by external sources and model-based amounts. Under SFAS No. 157, contracts are classified in their entirety according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, these contracts are classified as Level 3 under SFAS No. 157. At June 30, 2008 and December 31, 2007, the sources of the fair value of wholesale derivative contracts are included in the following tables:

	Fair Value of Wholesale Contracts at June 30, 2008			
(Millions of Dollars) **Sources of Fair Value**	**Maturity Less than One Year**	**Maturity of One to Four Years**	**Maturity in Excess of Four Years**	**Total Fair Value**
Prices actively quoted	$ 5.9	$ 8.5	$ 0.6	$ 15.0
Prices provided by external sources	(16.9)	(44.0)	(5.0)	(65.9)

Model-based [1]		(0.6)		(6.9)		(16.2)		(23.7)
Totals	$	(11.6)	$	(42.4)	$	(20.6)	$	(74.6)

	Fair Value of Wholesale Contracts at December 31, 2007							
(Millions of Dollars) Sources of Fair Value	Maturity Less than One Year		Maturity of One to Four Years		Maturity in Excess of Four Years		Total Fair Value	
Prices actively quoted	$	(4.7)	$	(0.2)	$	1.4	$	(3.5)
Prices provided by external sources		(24.0)		(38.8)		(13.4)		(76.2)
Model-based		-		4.3		(18.6)		(14.3)
Totals	$	(28.7)	$	(34.7)	$	(30.6)	$	(94.0)

(1) The model-based amounts include the effects of implementing SFAS No. 157.

For the three and six months ended June 30, 2008, the changes in fair value of these contracts are included in the following table:

(Millions of Dollars)	For the Three Months Ended June 30, 2008 Total Portfolio Fair Value		For the Six Months Ended June 30, 2008 Total Portfolio Fair Value	
Fair value of wholesale contracts outstanding at the beginning of the period	$	(81.1)	$	(94.0)
Pre-tax effects of implementing SFAS No. 157 ($3.7 million after-tax) [1]		-		(6.1)
Contracts realized or otherwise settled during the period [2]		8.8		27.0
Period change in unrealized losses included in earnings		(2.3)		(1.5)
Fair value of wholesale contracts outstanding at the end of the period	$	(74.6)	$	(74.6)

(1)

Pre-tax effect recorded in fuel, purchased and net interchange power on the condensed consolidated statement of income.

(2)

Amount includes purchases, issuances and settlements of $5.3 million and $20.7 million for the three and six months ended June 30, 2008, respectively, and realized intra-month gains of $3.5 million and $6.3 million for the three and six months ended June 30, 2008, respectively.

For further information regarding Select Energy's derivative contracts, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Counterparty Credit Risk: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in Select Energy establishing credit limits prior to entering into contracts. The appropriateness of these limits is subject to our continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. At June 30, 2008, approximately 84 percent of Select Energy's counterparty credit exposure to wholesale counterparties was non-rated, approximately 15 percent was rated BBB- or better and approximately one percent was collateralized. The bulk of the non-rated credit exposure is comprised of one counterparty, which is a non-rated public entity that we believe to be creditworthy. To date, this counterparty has met all of its contractual obligations.

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 statements. Our management communicates to and discusses with our Audit Committee of the Board of Trustees all critical accounting policies and estimates. All of these critical accounting policies and estimates were reported in the 2007 Form 10-K. There have been no material changes with regard to these critical accounting policies and estimates, except as follows:

Fair Value Measurements: We adopted SFAS No. 157 as of January 1, 2008. SFAS No. 157 defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). It establishes a framework for measuring fair value, using a three level hierarchy based upon the observability of inputs to the valuations. See Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 3, "Fair Value Measurements," to the accompanying condensed consolidated financial statements for further information.

As of January 1, 2008, we applied SFAS No. 157 to our regulated and unregulated companies derivative contracts that are recorded at fair value and to the marketable securities held in NU s Rabbi Trust and WMECO s prior spent nuclear fuel trust. SFAS No. 157 also applies to investment valuations for our pension and other postretirement benefit plans beginning as of December 31, 2008, and beginning in 2009, to nonrecurring fair value measurements of non-financial assets and liabilities, such as goodwill and asset retirement obligations. Implementing SFAS No. 157 for our marketable securities expanded our financial statement disclosures, but did not affect the recorded fair value of investments.

In the first six months of 2008, we recorded an after-tax reduction of earnings of $2.4 million as a result of applying SFAS No. 157 to derivative liabilities for Select Energy s remaining wholesale marketing contracts, net of a $1.3 million benefit from partially reversing the implementation charge as we served rather than exited these contracts during the period.

As a result of implementing SFAS No. 157, we also recorded changes in fair value of certain derivative contracts of CL&P. Because CL&P is a cost-of-service, rate regulated entity, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers, and an offsetting regulatory asset or liability was recorded to reflect these changes. SFAS No. 157 resulted in a total increase to CL&P's derivative liabilities, with an offset to regulatory assets of approximately $590 million and a total decrease to derivative assets, with an offset to regulatory liabilities, of approximately $30 million. The increase to CL&P's derivative liabilities primarily resulted from an increase in the negative fair value of a contract for differences with a generating plant to be built to reflect the estimated cost to exit this contract, reflecting an increase in the probability that the plant will be built and the recognition of a loss at the inception of the contract of approximately $100 million that was deferred under previous accounting guidance.

If we do not exit but rather serve out our derivative liability contracts, we will not make payments for some portion of the negative fair value recorded for the contracts. Likewise, we could receive more cash for derivative assets than the fair value recorded.

We use quoted market prices when available to determine fair values of financial instruments and classify those valuations as Level 1 within the fair value hierarchy. If quoted market prices are not available, fair value is determined using quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments that are not active and model-derived valuations in which all significant inputs are observable. These valuations are classified as Level 2 within the fair value hierarchy.

Many of our derivative contracts that are recorded at fair value are classified as Level 3 within the hierarchy and are valued using models that incorporate both observable and unobservable inputs. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs utilized in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under full requirements and supplemental sales contracts, and market volatilities. Discounted cash flow valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect nonperformance risk, including credit risk. Contracts valued using models 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 as Level 3 even though there may be some significant inputs that are readily observable.

Total Level 3 derivative assets were 76 percent of our total assets measured at fair value, and Level 3 derivative liabilities were 100 percent of our total liabilities measured at fair value at June 30, 2008. A significant portion of our Level 3 derivative liabilities relate to the regulated company derivative contracts for which changes in fair value do not affect our earnings due to our use of regulatory accounting. Changes in fair value of these contracts are not material to our liquidity or capital resources because the costs and benefits of the contracts are recoverable from or refundable to customers on a timely basis.

We review and update our fair value hierarchy classifications on a quarterly basis. As of June 30, 2008, investment securities are classified in Levels 1 and 2. Classifications of an investment security or group of investment securities into Level 3 may occur if a significant amount of inputs to their valuation is no longer observable due to a decline in market activity or liquidity.

Changes in fair value of the remaining wholesale marketing contracts of our unregulated businesses are recorded in fuel, purchased and net interchange power on the accompanying condensed consolidated statements of income. For the three and six months ended June 30, 2008, there were net unrealized losses of $1.4 million and $0.9 million, respectively, related to the valuation of these contracts. For the three and six months ended June 30, 2008, there were net realized gains of $2.1 million and $3.8 million, respectively, related to the valuation of these contracts. Key drivers of variability in fair values include changes in energy prices and expected volumes under the contracts.

Changes in fair value of the regulated company derivative contracts are recorded as regulatory assets or liabilities, as we expect to recover these costs in rates. These valuations are sensitive to the prices of energy and energy related products in future years for which markets have not yet developed. Assumptions made to implement SFAS No. 157 had a significant effect on derivative values, and changes in assumptions may continue to have significant effects.

For further information on derivative contracts, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Accounting for Environmental Reserves: Environmental reserves are accrued when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Adjustments made to environmental reserves could have a significant effect on earnings. Our approach estimates these liabilities based on the most likely action plan from a variety of available remediation options, ranging from no action to remedies ranging from establishing institutional controls to full site remediation and long-term monitoring. The estimates associated with each possible action plan are based on findings through various phases of site assessments.

These estimates are based on currently available information from presently enacted state and federal environmental laws and regulations and several cost estimates from third-party engineering and remediation contractors who would be performing the work. These estimates also take into consideration prior experience in remediating contaminated sites and data released by the United States Environmental Protection Agency and other organizations. These estimates are subjective in nature partly because there are usually several different remediation options from which to choose when working on a specific site. These estimates are subject to revisions in future periods based on actual costs or new information concerning either the level of contamination at the site or newly enacted laws and regulations. The amounts recorded as environmental liabilities on the condensed consolidated balance sheets represent our best estimate of the liability for environmental costs based on current site information from site assessments and remediation estimates. These liabilities are recorded on an undiscounted basis.

Holyoke Water Power Company (HWP) is a subsidiary of NU that owns a minimal amount of transmission property and has limited operating activities. HWP continues to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP is at least partially responsible for this site, and has already conducted substantial remediation activities. HWP first established a reserve for this site in 1994. A pre-tax charge of approximately $3 million was recorded in the second quarter of 2008 to reflect the estimated cost of further tar delineation and site characterization studies, as well as certain remediation costs that are considered to be probable and estimable as of June 30, 2008. The cumulative expense recorded to this reserve through June 30, 2008 was approximately $15.9 million, of which $12.6 million had been spent, leaving approximately $3.3 million in the reserve as of June 30, 2008.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, which shares responsibility for the site, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP s 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP is developing plans for additional investigations to accord with MA DEP s guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

At this time, we believe that the $3.3 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $3.3 million to $4 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur through 2008 and 2009, and possibly into 2010.

There are many outcomes that could affect our estimates and require an increase to the reserve or range of costs, and a reserve increase would be reflected as a charge to pre-tax earnings. However, we cannot reasonably estimate the range of additional investigation and remediation costs because they will depend on, among other things, the level and extent of the remaining tar that may be required to be remediated, the extent of HWP s responsibility and the related scope and timing, all of which are difficult to estimate because of a number of uncertainties at this time. As of June 30, 2008, HWP had $3.3 million remaining in the reserve related to this matter, and further developments may require a material increase to this reserve.

HWP's share of the remediation costs related to this site is not recoverable from customers.

Presentation: In accordance with GAAP, our consolidated financial statements include all subsidiaries over which control is maintained and would include any variable interest entities (VIE) for which we are the primary beneficiary as defined in FASB Interpretation No. (FIN) 46(R), "Consolidation of Variable Interest Entities." Determining whether we are the primary beneficiary of a VIE is complex and subjective, and requires our judgment. There are a variety of facts and circumstances and a number of variables taken into consideration to determine whether we are considered the primary beneficiary of a VIE. A change in facts and circumstances or a change in accounting guidance could require us to reconsider whether or not we are the primary beneficiary of the VIE.

The Energy Independence Act required the DPUC to consider the impact on distribution companies of entering into long-term contracts for capacity and contracts to purchase renewable energy products from new generating plants. We reviewed each contract to determine the appropriate accounting treatment based on the terms of the contracts. Determining whether or not consolidation is required involves our judgment.

In April 2007, CL&P entered into a 15-year agreement beginning in 2010 to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. In May 2008, CL&P and UI entered into six additional long-term agreements with proposed renewable energy plants. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these contracts with 80 percent to CL&P and 20 percent to UI. We evaluated whether entering into these contracts would require consolidation and determined that consolidation of the projects would not be required. The review of these contracts required significant management judgment.

In 2007, CL&P entered into two contracts for differences (CfDs) associated with the capacity of two generating projects to be built or modified and UI entered into two capacity-related CfDs, one with a generating project to be built and one with a new demand response project. The contracts, referred to as CfDs, obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs with 80 percent to CL&P and 20 percent to UI. We determined that these contracts are derivatives and do not require consolidation.

The Energy Efficiency Act required electric distribution companies, including CL&P, and allowed others to file proposals with the DPUC to build cost-of-service peaking generation facilities. On June 25, 2008, the DPUC issued a final decision approving three proposed peaking generation units totaling 678 MW of summer peaking capacity and rejecting nine others, including the two units proposed by CL&P. In the third quarter of 2008, CfDs with the developers of the three approved units were signed or are expected to be signed, two by CL&P and one by UI. As directed by the DPUC, CL&P and UI have entered into another sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfD contracts.

The CfDs for peaking generation pay the developer the difference between floating capacity, forward reserve and energy market revenues, and a cost-of-service payment stream for 30 years. The ultimate cost to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. We are evaluating whether these contracts require consolidation. Unlike the projects with which we have capacity CfDs, CL&P may be determined to be the primary beneficiary under the peaker CfDs and be required to consolidate these projects under the current requirements of FIN 46(R) because under the peaker CfDs, CL&P is required to reimburse the projects on a cost of service basis, which will result in CL&P absorbing more of the variability of the projects, including the costs of construction and operation. Consolidation of these projects would likely result in significant increases to the property, plant and equipment and long-term debt balances on our consolidated balance sheets.

The FASB is in the process of reinterpreting the consolidation requirements of FIN 46(R). The expected guidance could eliminate the requirement for consolidation when we do not have the power to direct matters that significantly impact the plant s activities. CL&P and UI do not have this power over peaker plant operations, and it is possible that CL&P would not be required to consolidate the peaker projects if and when the new guidance becomes effective. Changes in facts and circumstances and changes in accounting guidance resulting in reevaluation of the accounting treatment of these contracts could have a significant impact on the accompanying consolidated financial statements.

Other Matters

Contractual Obligations and Commercial Commitments: For updated information regarding NU's contractual obligations and commercial commitments at June 30, 2008, see Note 5B, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the condensed consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes 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 these "forward looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and 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, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels and timing of capital expenditures, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports filed with the SEC and we encourage you to consult such disclosures.

All such factors are difficult to predict, contain uncertainties which may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each of which 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 "Risk Factors" included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2007. This Quarterly Report on Form 10-Q also describes material contingencies and critical accounting policies and estimates in the accompanying "Management s Discussion and Analysis" and "Notes to Consolidated Financial Statements." We encourage you to review these items.

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

RESULTS OF OPERATIONS - NU CONSOLIDATED

The following table provides the variances in income statement line items for the condensed consolidated statements of income for NU included in this report on Form 10-Q for the three and six months ended June 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Second Quarter	Percent	Six Months	Percent
Operating Revenues:	$ (67)	(5) %	$ (250)	(8) %
Operating Expenses:				
Fuel, purchased and net interchange power	(143)	(18)	(390)	(21)
Other	(9)	(4)	40	8
Maintenance	11	18	22	21
Depreciation	5	8	9	7
Amortization of regulatory assets/(liabilities), net	45	(a)	68	(a)
Amortization of rate reduction bonds	1	2	2	2
Taxes other than income taxes	2	3	1	1
Total operating expenses	(88)	(7)	(248)	(9)
Operating Income	21	18	(2)	(1)
Interest expense, net	6	11	10	8
Other income, net	(2)	(13)	(2)	(8)
Income/(loss) from continuing operations before income tax (benefit)/expense	13	19	(14)	(8)
Income tax expense/(benefit)	1	7	(8)	(14)
Preferred dividends of subsidiary	-	-	-	-
Income/(loss) from continuing operations	12	25	(6)	(5)
Income/(loss) from discontinued operations	(3)	(100)	(1)	(100)
Net Income	$ 9	19 %	$ (7)	(6) %

(a) Percent greater than 100.

Net income was $9 million higher in the second quarter of 2008 primarily due to the growth in the company's transmission segment and was $7 million lower for the six months primarily due to a $29.8 million after-tax charge associated with a litigation settlement.

Comparison of the Second Quarter of 2008 to the Second Quarter of 2007

Operating Revenues

Operating revenues decreased $67 million in 2008 primarily due to lower revenues from NU Enterprises ($40 million) and lower revenues from the regulated companies ($26 million). NU Enterprises's revenues decreased $40 million due to the exit from components of the competitive businesses. The lower regulated revenues were primarily due to the recovery of a lower level of CL&P distribution related expenses passed through to customers through regulatory tracking mechanisms.

Revenues from the regulated companies decreased $26 million due to lower distribution segment revenues ($43 million), partially offset by higher transmission segment revenues ($17 million). Distribution segment revenues decreased $43 million primarily due to lower electric distribution revenues ($61 million), partially offset by higher gas distribution revenues ($18 million). Transmission segment revenues increased $17 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Electric distribution revenues decreased $61 million due to the components of CL&P, PSNH and WMECO retail revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($65 million), partially offset by the component of revenues which flows through to earnings, which increased $24 million. The distribution revenue tracking components decreased $65 million primarily due to the pass-through of lower energy supply costs ($77 million), lower CL&P revenue associated with the recovery of delivery-related FMCC ($27 million) and a decrease in PSNH s SCRC revenues mainly as a result of a rate decrease effective for 2008 ($12 million), partially offset by higher CL&P wholesale revenues primarily due to an increase in the market price of energy relating to sales of IPP generation to ISO-NE ($39 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 distribution component of electric distribution segment revenues which flows through to earnings increased $24 million primarily due to increases in retail rates at each of the regulated companies ($28 million), partially offset by lower retail electric sales ($4 million). Retail electric sales decreased by 4.5 percent in 2008 compared with 2007 (a 4.1 percent decrease on a weather normalized basis). Firm gas sales increased 2.4 percent in 2008 compared with 2007 (a 7.4 percent increase on a weather normalized basis).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $143 million in 2008 due to lower costs at the regulated companies ($92 million) and lower expenses at NU Enterprises ($51 million). Fuel expense from the regulated companies decreased primarily due to lower fuel, purchased and net interchange power expenses at CL&P and WMECO ($123 million), mainly due to a decrease in standard offer supply costs as a result of a reduction in load caused by customer migration to third party suppliers, partially offset by higher PSNH ($17 million) and Yankee Gas fuel expense ($14 million). NU Enterprises' fuel expenses decreased due to the exit from certain components of the competitive businesses.

Other Operation

Other operation expenses decreased $9 million in 2008 primarily due to lower regulated companies distribution and transmission segment expenses ($17 million), partially offset by higher NU Enterprises expenses ($8 million). NU Enterprises expenses are higher by $8 million primarily due to higher operating costs at the remaining service businesses.

Lower regulated company distribution and transmission segment expenses of $17 million are primarily due to lower CL&P distribution segment expenses related to transmission ($29 million), partially offset by higher CL&P Energy Independence Act (EIA) expenses which will be recovered through the FMCC deferral mechanism ($8 million).

Maintenance

Maintenance expenses increased $11 million in 2008 primarily due to higher regulated company distribution expenses ($8 million), generation segment expenses as a result of the Merrimack Station Unit 2 maintenance outage ($2 million) and higher transmission line expenses ($1 million). Regulated company distribution expenses are $8 million higher mainly as a result of higher tree trimming ($3 million), substation equipment ($1 million), line transformers ($1 million) and underground line activities ($1 million).

Depreciation

Depreciation increased $5 million in 2008 primarily due to higher distribution and transmission depreciation expense as a result of higher plant balances from ongoing construction programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net increased $45 million in 2008 for the distribution segment primarily due to higher amortization at CL&P ($47 million) resulting from a higher recovery of transition costs ($34 million) and a credit in 2007 pertaining to the refund of the GSC over-recovery ($7 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $1 million in 2008. The higher portion of principal within rate reduction bond payments resulted in a corresponding increase in the amortization of rate reduction bonds. This increase was partially offset by a decrease at PSNH resulting from the retirement of $50 million of rate reduction bonds in January 2008.

Taxes Other than Income Taxes

Taxes other than income taxes increased $2 million in 2008 primarily due to higher CL&P and PSNH property taxes on higher plant balances.

Interest Expense, Net

Interest expense, net increased $6 million in 2008 primarily due to higher long-term debt interest ($6 million) resulting from the issuance of new long-term debt in 2007 and the first half of 2008 and higher short-term debt interest ($2 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($3 million).

Other Income, Net

Other income, net decreased $2 million in 2008 primarily due to lower investment income ($4 million) and EIA incentives ($1 million), partially offset by higher AFUDC equity ($3 million) mainly as a result of higher eligible construction work in progress and lower short-term debt resulting in an increase in the construction work in progress financed by permanent capital.

Income Tax Expense/(Benefit)

Income tax expense/(benefit) increased $1 million primarily due to higher CL&P pre-tax earnings related tax expense increases of ($5 million); partially offset by pre-tax expense decreases at NU Parent and other ($4 million). NU projects its effective tax rate, excluding discrete items, to be in the range of 30-32 percent for the year, for purposes of estimating tax expense. These rates can fluctuate. NU's current projected effective tax rate is lower than the statutory rate due primarily to temporary flow through depreciation benefits, Medicare subsidy and tax credits.

Income/(Loss) from Discontinued Operations

See Note 7, "Discontinued Operations," to the condensed consolidated financial statements for a description and explanation of the discontinued operations.

Comparison of the First Six Months of 2008 to the First Six Months of 2007

Operating Revenues

Operating revenues decreased $250 million in 2008 primarily due to lower revenues from the regulated companies ($170 million) and lower revenues from NU Enterprises ($80 million). NU Enterprises's revenues decreased $80 million due to the exit from components of the competitive businesses. The lower regulated revenues were primarily due to the recovery of a lower level of CL&P distribution related expenses passed through to customers through regulatory tracking mechanisms.

Revenues from the regulated companies decreased $170 million due to lower distribution segment revenues ($210 million), partially offset by higher transmission segment revenues ($40 million). Distribution segment revenues decreased $210 million primarily due to lower electric distribution revenues ($243 million), partially offset by higher gas distribution revenues ($33 million). Transmission segment revenues increased $40 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Electric distribution revenues decreased $243 million due to the components of CL&P, PSNH and WMECO retail revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($246 million), partially offset by the component of revenues which flows through to earnings, which increased $44 million. The distribution revenue tracking components decreased $246 million primarily due to the pass through of lower energy supply costs ($228 million) and lower CL&P revenue associated with the recovery of delivery-related FMCC ($61 million), partially offset by higher CL&P wholesale revenues primarily due to an increase in the market price of energy related to sales of IPP generation to ISO-NE ($48 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or under collections recovered from customers in future periods.

The distribution component of the electric distribution segment which flows through to earnings increased $44 million primarily due to increases in retail rates at each of regulated companies ($54 million), partially offset by lower retail electric sales ($7 million). Retail electric sales decreased by 3.1 percent in 2008 compared with 2007 (a 2.6 percent decrease on a weather normalized basis). Firm gas sales decreased 2.6 percent in 2008 compared with 2007 (a 1.2 percent increase on a weather normalized basis).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $390 million in 2008 due to lower costs at the regulated companies ($296 million) and lower expenses at NU Enterprises ($94 million). Fuel expense from the regulated companies decreased primarily due to lower fuel, purchased and net interchange power expenses at CL&P and WMECO ($327 million), mainly due to a decrease in standard offer supply costs as a result of a reduction in load caused by customer migration to third party suppliers, partially offset by higher Yankee Gas ($16 million) and PSNH fuel expense ($15 million). NU Enterprises' fuel expenses decreased due to the exit from certain components of the competitive businesses.

Other Operation

Other operation increased $40 million in 2008 primarily due to higher NU parent and other companies' expenses ($48 million), NU Enterprises expenses ($20 million), partially offset by lower regulated companies distribution and transmission segment expenses ($27 million). NU parent and parent and other companies' expenses are higher by $48 million in 2008 primarily due to the $49.5 million payment to Con Edison resulting from the settlement of litigation and NU Enterprises expenses are higher by $20 million primarily due to higher operating costs at the remaining service businesses.

Lower regulated company distribution and transmission segment expenses of $27 million are primarily due to lower CL&P distribution segment expenses related to transmission ($44 million), partially offset by higher customer accounts expenses at CL&P, PSNH, WMECO and Yankee ($10 million) and CL&P higher EIA expenses which will be recovered through the FMCC deferral mechanism ($9 million).

Maintenance

Maintenance expenses increased $22 million in 2008 primarily due to higher regulated company distribution expenses ($19 million), generation segment expenses related to the Merrimack Station Unit 2 maintenance outage ($2 million) and higher transmission line expenses ($2 million). Regulated company distribution expenses are $19 million higher mainly as a result of higher tree trimming ($6 million), overhead line maintenance expenses due to more storm-related expenses ($6 million), substation equipment ($2 million), underground line activities ($2 million) and line transformers ($1 million).

Depreciation

Depreciation increased $9 million in 2008 primarily due to higher distribution and transmission depreciation expense as a result of higher plant balances from ongoing construction programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net increased $68 million in 2008 for the distribution segment primarily due to higher amortization at CL&P ($67 million) resulting from a higher recovery of transition costs ($38 million), a credit in 2007 pertaining to the refund of the GSC provision for rate refunds ($15 million) and higher amortization of SBC ($15 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $2 million in 2008. The higher portion of principal within the rate reduction bond payments results in a corresponding increase in the amortization of rate reduction bonds.

Interest Expense, Net

Interest expense, net increased $10 million in 2008 primarily due to higher long-term debt interest ($13 million) resulting from the issuance of new long-term debt in 2007 and the first half of 2008, and higher short-term debt interest ($3 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($5 million).

Other Income, Net

Other income, net decreased $2 million in 2008 primarily due to lower investment income ($11 million) mostly due to lower NU parent cash which is being invested as equity in the operating companies, partially offset by higher AFUDC equity ($9 million) mainly as a result of higher eligible construction work in progress and lower short-term debt resulting in an increase in the construction work in progress financed by permanent capital.

Income Tax Expense/(Benefit)

Income tax expense/(benefit) decreased $8 million; $25 million from NU Parent and other including $20 million from the Con Edison settlement and $4 million from other pre-tax expense increases, partially offset by pre-tax earnings related tax expense increases at CL&P ($10 million), PSNH ($4 million) and YGS ($3 million). NU projects its effective tax rate, excluding discrete items, to be in the range of 30-32 percent for the year, for purposes of estimating tax expense. These rates can fluctuate. NU's current projected effective tax rate is lower than the statutory rate due primarily to temporary flow through depreciation benefits, Medicare subsidy and tax credits.

Income/(Loss) from Discontinued Operations

See Note 7, "Discontinued Operations," to the condensed consolidated financial statements for a description and explanation of the discontinued operations.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

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

CL&P is a wholly owned subsidiary of NU. This discussion should be read in conjunction with NU's Management's Discussion and Analysis of Financial Condition and Results of Operations, condensed consolidated financial statements and footnotes in this Form 10-Q, the First Quarter 2008 Form 10-Q and the NU 2007 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the condensed consolidated statements of income for CL&P included in this report on Form 10-Q for the three and six months ended June 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Second Quarter	**Percent**	**Six Months**	**Percent**
Operating Revenues:	$ (48)	(6) %	$ (207)	(11) %
Operating Expenses:				
Fuel, purchased and net interchange power	(118)	(23)	(313)	(26)
Other Operation	(11)	(8)	(16)	(6)
Maintenance	4	13	11	23
Depreciation	1	4	2	3
Amortization of regulatory assets, net	47	(a)	67	(a)
Amortization of rate reduction bonds	2	8	5	7
Taxes other than income taxes	1	2	1	1
Total operating expenses	(74)	(9)	(243)	(14)
Operating Income	26	40	36	26

Interest expense, net		4	10			3	5	
Other income, net		3	39			9	70	
Income before income tax		25	66			42	48	
Income tax expense		5	37			10	39	
Net Income/(Loss)	$	20	79	%	$	32	52	%

(a) Percent greater than 100.

<u>Comparison of the Second Quarter of 2008 to the Second Quarter of 2007</u>

Operating Revenues

Operating revenues decreased $48 million in 2008 due to lower distribution segment revenues ($72 million), partially offset by higher transmission segment revenues ($24 million).

The distribution segment revenues decreased $72 million primarily due to the components of revenues, which are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs ($73 million). The distribution segment revenue tracking components decreased $73 million primarily due to a decrease in revenues associated with the recovery of generation service and related congestion charges ($88 million) and delivery-related FMCC ($27 million), partially offset by higher wholesale revenues ($39 million). The lower generation service and related congestion charge revenue was primarily due to a reduction in load caused primarily by customer migration to third party suppliers as well as lower congestion costs in 2008. The lower delivery-related FMCC revenue was primarily due to a decrease in this rate component in 2008 as a result of lower reliability must run (RMR), VAR support and southwest Connecticut energy resource costs in 2008, as well as a larger prior year over-recovery being refunded to customers in 2008 as compared to 2007. The higher wholesale revenue was primarily due to an increase in the market price of energy relating to sales of IPP generation to ISO-NE. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The distribution component of revenues which impacts earnings increased $19 million primarily due to the rate increase effective February 1, 2008, partially offset by lower retail sales. Retail sales decreased 5.8 percent in 2008 compared to the same period in 2007.

Transmission segment revenues increased $24 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $118 million primarily due to a decrease in deferred fuel costs ($62 million), a decrease in generation service supply costs ($54 million) and lower other purchased power costs ($2 million), all of which are included in DPUC approved tracking mechanisms. The $62 million decrease in deferred fuel costs was primarily due to the combined effect of CL&P having a supply and delivery-related net FMCC over-recovery in the second quarter of 2007 and a supply and delivery-related net FMCC under-recovery in the second quarter of 2008. The $54 million decrease in supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers. These supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply SS and LRS load through a competitive solicitation process.

Other Operation

Other operation expenses decreased $11 million primarily due to lower distribution segment expenses relating to transmission ($29 million), partially offset by higher EIA expenses which will be recovered through the FMCC deferral mechanism ($8 million), higher storm expenses ($5 million), and higher administrative and general expenses ($3 million) primarily related to higher outside service costs.

Maintenance

Maintenance expenses increased $4 million in 2008 primarily due to higher tree trimming expenses ($2 million) and higher transmission substation expenses ($1 million).

Depreciation

Depreciation expense increased $1 million primarily due to higher utility plant balances resulting from ongoing construction programs.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $47 million primarily due to a higher recovery of transition costs ($34 million), a credit in 2007 pertaining to the refund of the GSC over-recovery ($7 million) and higher amortization of SBC ($7 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $2 million. The higher portion of principal within the rate reduction bonds payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $1 million primarily due to higher property taxes on higher plant balances.

Interest Expense, Net

Interest expense, net increased $4 million primarily due to higher long-tem debt ($4 million) interest resulting from the $200 million new debt issuance in September 2007 and the $300 million debt issuance in May 2008, higher short-term debt interest ($1 million) and higher FMCC deferral interest ($1 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($2 million).

Other Income, Net

Other income, net increased $3 million primarily due to higher equity AFUDC income ($3 million) as a result of higher eligible CWIP due to the transmission construction program resulting in an increase in CWIP financed by equity, and higher EIA incentives income ($1 million), partially offset by a higher investment loss ($2 million).

Income Tax Expense

Income tax expense increased $5 million primarily due to higher pre-tax earnings being subject to tax at marginal rates, partially offset by flow through impacts associated with depreciation and bad debt reserve changes.

Comparison of the First Six Months of 2008 to the First Six Months of 2007

Operating Revenues

Operating revenues decreased $207 million in 2008 due to lower distribution segment revenues ($252 million), partially offset by higher transmission segment revenues ($45 million).

The distribution segment revenues decreased $252 million primarily due to the components of revenues, which are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs ($250 million). The distribution segment revenue tracking components decreased $250 million primarily due to a decrease in revenues associated with the recovery of generation service and related congestion charges ($241 million) and delivery-related FMCC ($61 million), partially offset by higher wholesale revenues ($48 million). The lower generation service and related congestion charge revenue was primarily due to a reduction in load caused primarily by customer migration to third party suppliers as well as lower congestion costs in 2008. The lower delivery-related FMCC revenue was primarily due to a decrease in this rate component in 2008 as a result of lower RMR, VAR support and southwest Connecticut energy resource costs in 2008, as well as a larger prior year over-recovery being refunded to customers in 2008 as compared to 2007. The higher wholesale revenue was primarily due to an increase in the market price of energy relating to sales of IPP generation to ISO-NE. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The distribution component of revenues which impacts earnings increased $32 million primarily due to the rate increase effective February 1, 2008, partially offset by lower retail sales. Retail sales decreased 4 percent in 2008 compared to the same period in 2007.

Transmission segment revenues increased $45 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $313 million primarily due to a decrease in generation service supply costs ($195 million), a decrease in deferred fuel costs ($109 million) and lower other purchased power costs ($9 million), all of which are included in DPUC approved tracking mechanisms. The $195 million decrease in supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers. These supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply SS and LRS load through a competitive solicitation process. The $109 million decrease in deferred fuel costs was primarily due to the combined effect of CL&P having a supply and delivery-related net FMCC over-recovery in the first six months of 2007 and a supply and delivery-related net FMCC under-recovery in the first six months of 2008.

Other Operation

Other operation expenses decreased $16 million primarily due to lower distribution segment expenses relating to transmission ($44 million), partially offset by higher EIA expenses which will be recovered through the FMCC deferral mechanism ($9 million), higher storm expenses ($5 million), higher administrative and general expenses primarily related to higher outside service costs ($4 million), higher Summer Saver Rewards Program expenses which will be recovered through the SBC deferral mechanism ($3 million), and higher distribution line expenses ($2 million).

Maintenance

Maintenance expenses increased $11 million in 2008 primarily due to higher tree trimming expenses ($4 million), higher distribution line ($3 million), higher transmission substation equipment ($2 million), and higher line transformer activities ($1 million).

Depreciation

Depreciation expense increased $2 million primarily due to higher utility plant balances resulting from ongoing construction programs.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $67 million primarily due to a higher recovery of transition costs ($38 million), a credit in 2007 pertaining to the refund of the GSC over-recovery ($15 million) and higher amortization of SBC ($15 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $5 million. The higher portion of principal within the rate reduction bonds payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $1 million primarily due to higher property taxes on higher plant balances.

Interest Expense, Net

Interest expense, net increased $3 million primarily due to higher long-term debt interest ($10 million) resulting from the $200 million debt issuance in September 2007, the $300 million debt issuance in March 2007 and the $300 million debt issuance in May 2008, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($4 million) and lower debt AFUDC ($4 million).

Other Income, Net

Other income, net increased $9 million primarily due to higher equity AFUDC income ($8 million) as a result of higher eligible CWIP due to the transmission construction program and lower short term debt resulting in an increase in CWIP financed by equity, and higher EIA incentives income ($4 million), partially offset by a higher investment loss ($3 million).

Income Tax Expense

Income tax expense increased $10 million primarily due to higher pre-tax earnings being subject to tax at marginal rates, partially offset by flow through impacts associated with depreciation and bad debt reserve changes.

LIQUIDITY

CL&P had consolidated operating cash flows of $124 million, after rate reduction bond payments, in the first half of 2008, compared with operating cash flows of $157.8 million, after rate reduction bond payments but before tax payments of approximately $177.2 million related to the 2006 sale of NU's competitive generation business, in the first half of 2007. Other drivers resulting in decreased operating cash flows in 2008 from 2007 are a reduction from regulatory refunds and underrecoveries (net of income tax impacts) and a net reduction in other working capital items, offset by a benefit from counterparty deposits.

CL&P projects consolidated operating cash flows of approximately $300 million to $350 million in 2008, after approximately $170 million of payments to retire CL&P's rate reduction bonds**.** NU expects to receive a potential net income tax settlement of approximately $70 million in the second half of 2008 and a reduction in income tax payments of $35 million related to bonus depreciation adjustments over the remainder of the year, both of which would primarily effect the operating cash flows of CL&P.

Cash capital expenditures included on the accompanying 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 portion of pension expense or income. CL&P s cash capital expenditures totaled $442 million in the first half of 2008, compared with $353.2 million in the first half of 2007. This increase was primarily the result of higher transmission capital expenditures in 2008.

On May 27, 2008, CL&P sold $300 million of first and refunding mortgage bonds due May 1, 2018 and carrying a coupon of 5.65 percent. Proceeds from the issuance were used to repay short-term debt, and fund the company s ongoing capital investment programs.

As of June 30, 2008, CL&P had no borrowings outstanding under the $400 million credit facility it shares with other NU subsidiaries. In addition, CL&P had an arrangement with CRC and a financial institution under which the financial institution could purchase up to $100 million of CL&P's accounts receivable and unbilled revenues from CRC. On June 30, 2008, there were no receivables sold under that facility and CL&P chose to terminate the Receivables Purchase and Sales Agreement due to the availability and relative cost of other liquidity sources. At this time, CL&P has no further plans to securitize its accounts receivable and unbilled revenues and will utilize availability under its credit facility and other financing vehicles, as necessary, to fund its daily operating activities and capital programs.

Other financing activities for the first half of 2008 included a first quarter 2008 capital contribution from NU parent of $57.1 million, offset by $53.2 million in common dividends paid to NU parent during the first half of 2008.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

Management s Discussion and Analysis of

Financial Condition and Results of Operations

PSNH is a wholly owned subsidiary of NU. This discussion should be read in conjunction with NU s Management s Discussion and Analysis of Financial Condition and Results of Operations, condensed consolidated financial statements and footnotes in this Form 10-Q, the First Quarter 2008 Form 10-Q and the NU 2007 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the condensed consolidated statements of income for PSNH included in this report on Form 10-Q for the three and six months ended June 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Second Quarter	**Percent**	**Six Months**	**Percent**
Operating Revenues:	$ 24	10 %	$ 38	7 %
Operating Expenses:				
Fuel, purchased and net interchange power	17	13	16	6
Other Operation	6	13	6	6
Maintenance	7	29	9	23
Depreciation	1	3	1	2
Amortization of regulatory liabilities, net	(3)	(18)	-	-
Amortization of rate reduction bonds	(2)	(14)	(3)	(11)
Taxes other than income taxes	-	-	-	-
Total operating expenses	26	12	29	6
Operating Income	(2)	(5)	9	17

Interest expense, net		1	4		1	4
Other income, net		1	75		1	86
Income/(loss) before income tax		(2)	(7)		9	28
Income tax expense		-	-		4	49
Net Income/(Loss)	$	(2)	(10) %	$	5	20 %

(a) Percent greater than 100.

<u>Comparison of the Second Quarter of 2008 to the Second Quarter of 2007</u>

Operating Revenues

Operating revenues increased $24 million in 2008 due to higher distribution segment revenues ($20 million) and higher transmission segment revenues ($4 million).

The distribution segment revenues increased $20 million primarily due to an increase of the components of revenues which are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs ($17 million). The distribution revenue tracking components increased $17 million primarily due to the pass-through of higher energy supply costs ($15 million), higher retail transmission revenues ($5 million), higher wholesale revenue ($7 million), partially offset by a decrease in the SCRC ($12 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 distribution component of PSNH s retail revenues which impacts earnings increased $5 million as a result of the rate increases effective July 1, 2007 and January 1, 2008, partially offset by lower retail sales. Retail sales decreased 1.0 percent in 2008 compared to the same period in 2007.

Transmission segment revenues increased $4 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs increased $17 million primarily due to higher forward energy market prices, partially offset by a decrease in payments to higher priced IPPs in 2008 as contracts expired.

Other Operation

Other operation expenses increased $6 million primarily due to higher retail transmission expenses ($3 million) which are tracked and recovered through the distribution retail transmission tracking mechanism, as well as higher customer accounts expenses ($3 million).

Maintenance

Maintenance expenses increased $7 million primarily due to higher generation segment expenses ($2 million) as a result of the Merrimack Station Unit 2 maintenance outage, distribution overhead lines ($2 million) and substation ($1 million) primarily due to more storms in the second quarter of 2008 compared to 2007 as well as expenditures associated with the REP which began July 1, 2007.

Depreciation

Depreciation expense increased $1 million primarily due to higher utility plant balances.

Amortization of Regulatory Liabilities, Net

Amortization of regulatory liabilities, net decreased $3 million primarily due to the reduction in net deferrals associated with PSNH's ES, TCAM and SCRC tracking mechanisms ($5 million), offset in part by the amortization related to the rate case settlement effective July 1, 2007 ($2 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds decreased $2 million primarily due to the retirement of $50 million of rate reduction bonds in January 2008.

Interest Expense, Net

Interest expense, net increased $1 million primarily due to higher long-term debt interest as a result of the issuance of $70 million of first mortgage bonds in September 2007.

Other Income, Net

Other income, net increased $1 million primarily due to a higher AFUDC, as a result of a higher eligible CWIP and lower short-term debt resulting in an increase in construction work in progress financed by equity and higher investment income.

<u>Comparison of the First Six Months of 2008 to the First Six Months of 2007</u>

Operating Revenues

Operating revenues increased $38 million due to higher distribution segment revenues ($31 million), and higher transmission segment revenues ($8 million).

The distribution segment revenues increased $31 primarily million due to an increase of the components of revenues which are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs ($25 million). The distribution revenue tracking components increased $25 million primarily due to the pass-through of higher energy supply costs ($22 million), higher retail transmission revenues ($11 million), higher wholesale revenues ($8 million), partially offset by a decrease in the SCRC ($24 million). The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections recovered from customers in future periods.

The distribution component of PSNH s retail revenues which impacts earnings increased $12 million as a result of the rate increases effective July 1, 2007 and January 1, 2008, partially offset by lower retail sales. Retail sales decreased 0.5 percent in 2008 compared to 2007.

Transmission segment revenues increased $8 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs increased $16 million primarily due to higher forward energy market prices, partially offset by a decrease in payments to higher priced IPPs in 2008 as contracts expired.

Other Operation

Other operation expenses increased $6 million primarily due to higher retail transmission expenses ($7 million) which are tracked and recovered through the distribution retail transmission tracking mechanism, partially offset by lower administrative expenses ($2 million).

Maintenance

Maintenance expenses increased $9 million primarily due to higher generation segment expenses ($2 million) as a result of the Merrimack Station Unit 2 maintenance outage, distribution overhead lines ($4 million) and substation ($1 million) and tree trimming ($1 million) primarily due to more storms in 2008 compared to 2007 as well as expenditures associated with the REP which began July 1, 2007.

Depreciation

Depreciation expense increased $1 million primarily due to higher utility plant balances.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds decreased $3 million primarily due to the retirement of $50 million of rate reduction bonds in January 2008.

Interest Expense, Net

Interest expense, net increased $1 million primarily due to higher long-term debt interest as a result of the issuance of $70 million of first mortgage bonds in September 2007.

Other Income, Net

Other income, net increased $1 million primarily due to a higher AFUDC, as a result of a higher eligible CWIP and lower short-term debt resulting in an increase in construction work in progress financed by equity.

Income Tax Expense

Income tax expense increased $4 million due to higher pre-tax earnings and an increase in the effective tax rate.

LIQUIDITY

PSNH had consolidated operating cash flows of $27.8 million, after rate reduction bond payments of $24.4 million made during the first half of 2008, compared with operating cash flows of $27.1 million, after rate reduction bond payments of $25.5 million made in the first half of 2007. The slight increase in 2008 operating cash flows was primarily due to a decrease in regulatory refunds and underrecoveries of approximately $3 million, offset by net payments of $1.7 million upon the termination of PSNH s forward interest rate swap agreements related to its debt issuance of $110 million during the first half of 2008.

Cash capital expenditures included on the accompanying 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 portion of pension expense or income. PSNH s cash capital expenditures totaled $119.2 million in the first half of 2008, compared with $79.5 million in the first half of 2007. This increase was primarily the result of higher transmission capital expenditures in 2008.

On May 27, 2008, PSNH sold $110 million of first mortgage bonds due May 1, 2018 and carrying a coupon of 6 percent. Proceeds from the issuance were used to repay short-term debt and for general working capital purposes.

As of June 30, 2008, PSNH had no borrowings outstanding under the $400 million credit facility it shares with other NU subsidiaries. Other financing activities for the first half of 2008 included capital contributions from NU parent of $35.5 million and $18.2 million in common dividends paid to NU parent.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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

WMECO is a wholly owned subsidiary of NU. This discussion should be read in conjunction with NU's Management's Discussion and Analysis of Financial Condition and Results of Operations, condensed consolidated financial statements and footnotes in this Form 10-Q, the First Quarter 2008 Form 10-Q and the NU 2007 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the condensed consolidated statements of income for WMECO included in this report on Form 10-Q for the three and six months ended June 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Second Quarter	**Percent**	**Six Months**	**Percent**
Operating Revenues:	$ (8)	(7) %	$ (22)	(9) %
Operating Expenses:				
Fuel, purchased and net interchange power	(5)	(9)	(14)	(11)
Other Operation	(3)	(10)	(8)	(16)
Maintenance	-	-	1	8
Depreciation	-	-	-	-
Amortization of regulatory assets, net	2	90	2	52
Amortization of rate reduction bonds	-	-	-	-
Taxes other than income taxes	-	-	-	-
Total operating expenses	(6)	(5)	(19)	(9)
Operating Income	(2)	(22)	(3)	(11)

Interest expense, net		-	-		-	-
Other income, net		-	-		-	-
Income/(loss) before income tax		(2)	(31)		(3)	(17)
Income tax expense/(benefit)		(1)	(34)		(1)	(18)
Net Income/(Loss)	$	(1)	(29) %	$	(2)	(17) %

<u>Comparison of the Second Quarter of 2008 to the Second Quarter of 2007</u>

Operating Revenues

Operating revenues decreased $8 million in 2008 compared to the same period in 2007 due to lower distribution segment revenues ($9 million), partially offset by higher transmission segment revenues ($1 million).

The distribution segment revenues decreased $9 million primarily due to the components of revenues which are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs. The distribution revenue tracking components decreased $9 million primarily due to lower pension tracker and default service true-up revenues ($4 million), lower generation service revenue resulting from declining sales and load migration to competitive supply ($3 million) and lower retail transmission revenues ($3 million), partially offset by higher wholesale revenues ($2 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased $1 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $5 million primarily due to lower Basic Service supply costs resulting from declining sales and customer migration to competitive supply. The Basic Service supply costs are the contractual amounts we must pay to various suppliers that serve Basic Service load after winning a competitive solicitation process.

Other Operation

Other operation expenses decreased $3 million primarily due to lower administrative and general expenses ($2 million), mainly due to lower pension expense, which includes the regulatory deferral associated with the pension/PBOP tracker, and lower retail transmission expenses ($1 million). The decrease in retail transmission expenses is primarily due to the deferral, resulting from the regulatory tracking mechanism, mainly as a result of the combination of lower retail transmission revenue and higher retail transmission expense caused by higher RMR and LNS expenses.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $2 million primarily due to the deferral of transition revenues collected in excess of allowed costs recovery, resulting mainly from lower power contract net costs.

Income Tax Expense/(Benefit)

Income tax expense/(benefit) decreased $1 million due to lower pre-tax earnings.

Comparison of the First Six Months of 2008 to the First Six Months of 2007

Operating Revenues

Operating revenues decreased $22 million in 2008 compared to the same period in 2007 due to lower distribution segment revenues ($23 million), partially offset by higher transmission segment revenues ($1 million).

The distribution segment revenues decreased $23 million primarily due to the components of revenues which are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs ($22 million). The distribution revenue tracking components decreased $22 million primarily due to lower generation service revenue resulting from declining sales and load migration to competitive supply ($9 million), lower pension tracker and default service true-up revenues ($9 million) and lower retail transmission revenues ($6 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased $1 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses which are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $14 million primarily due to lower Basic Service supply costs resulting from declining sales and customer migration to competitive supply. The Basic Service supply costs are the contractual amounts we must pay to various suppliers that serve Basic Service load after winning a competitive solicitation process.

Other Operation

Other operation expenses decreased $8 million primarily due to lower retail transmission expenses ($4 million) and lower administrative and general expenses ($3 million), mainly due to lower pension expense, which includes the regulatory deferral associated with the pension/PBOP tracker. The decrease in retail transmission expenses is primarily due to the deferral, resulting from the regulatory tracking mechanism, mainly as a result of the combination of lower retail transmission revenue and higher retail transmission expense caused by higher RMR and LNS expenses.

Maintenance

Maintenance expenses increased $1 million primarily due to higher distribution line maintenance.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $2 million primarily due to the deferral of transition revenues collected in excess of allowed costs recovery, resulting mainly from lower power contract net costs.

Income Tax Expense/(Benefit)

Income tax expense/(benefit) decreased $1 million due to lower pre-tax earnings.

LIQUIDITY

WMECO had positive consolidated operating cash flows of $31 million, after rate reduction bond payments of $6.9 million, in the first half of 2008, compared with negative operating cash flows of $12 million, after rate reduction bond payments of $6.4 million, in the first half of 2007. The improvement in 2008 operating cash flows was primarily due to the payment of $47.9 million in federal and state income taxes in the first quarter of 2007, which was a result of the 2006 sale of our competitive generation business, offset by a decrease in regulatory overrecoveries of approximately $23 million.

Cash capital expenditures included on the accompanying 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 portion of pension expense or income. WMECO s cash capital expenditures totaled $27.9 million in the first half of 2008, compared with $21.9 million in the first half of 2007. This increase was primarily the result of higher transmission capital expenditures in 2008.

As of June 30, 2008, WMECO had no borrowings outstanding under the $400 million credit facility it shares with other NU subsidiaries. Other financing activities for the first half of 2008 included a capital contribution from NU parent of $16.3 million and $6.7 million in common dividends paid to NU parent.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

We utilize the sensitivity analysis methodology to disclose quantitative information for our commodity price risks (including where applicable capacity and ancillary components). Sensitivity analysis provides a presentation of the potential loss of future earnings, fair values or cash flows from market risk-sensitive instruments over a selected time period due to one or more hypothetical changes in commodity price components, or other similar price changes. Under sensitivity analysis, the fair value of the portfolio is a function of the underlying commodity components, contract prices and market prices represented by each derivative contract. For swaps, forward contracts and options, fair value reflects our best estimates considering over-the-counter quotations, time value and volatility factors of the underlying commitments. Exchange-traded futures and options are recorded at fair value based on closing exchange prices. The fair value of our other contracts is based on models. As Select Energy's contract volumes are winding down and are substantially hedged against price risks, the company has limited exposure to commodity price risks.

Wholesale Portfolio: When conducting sensitivity analyses of the change in the fair value of the wholesale portfolio, which includes a non-derivative power purchase contract, which would result from a hypothetical change in the future market price of electricity, the fair values of the contracts are determined from models that take into consideration estimated future market prices of electricity, the volatility of the market prices in each period, as well as the time value factors of the underlying commitments.

A hypothetical change in the fair value of the wholesale portfolio was determined assuming a 10 percent change in forward market prices. At June 30, 2008, we calculated the market price resulting from a 10 percent change in forward market prices of those contracts. A 10 percent increase in prices for all products would have resulted in a pre-tax increase in fair value of $3.5 million and a 10 percent decrease in prices for all products would have resulted in a pre-tax decrease in fair value of $3.7 million. A 10 percent increase in energy prices would have resulted in a $4.1 million pre-tax decrease, and a 10 percent decrease in energy prices would have resulted in a $3.9 million pre-tax increase. A 10 percent increase/(decrease) in capacity prices would have resulted in a $1.8 million pre-tax increase/(decrease). A 10 percent increase/(decrease) in ancillary prices would have resulted in a $5.8 million pre-tax increase/(decrease).

The impact of a change in electricity prices on wholesale transactions at June 30, 2008 are not necessarily representative of the results that will be realized, if such a change were to occur. Also, energy, capacity and ancillaries have different market volatilities. The derivative contracts in the wholesale portfolio are accounted for at fair value, and changes in market prices impact earnings.

Other Risk Management Activities

Interest Rate Risk Management: We manage our interest rate risk exposure in accordance with our written policies and procedures by maintaining a mix of fixed and variable rate long-term debt. At June 30, 2008, approximately 91 percent (85 percent including the long-term debt subject to the fixed-to-floating interest rate swap as variable rate long-term debt) of our long-term debt, including fees and interest due for spent nuclear fuel disposal costs, was at a fixed interest rate. The remaining long-term debt is at variable interest rates and is subject to interest rate risk that could result in earnings volatility. Assuming a one percentage point increase in our variable interest rate, annual interest expense would have increased by a pre-tax amount of $3.7 million. At June 30, 2008, we maintained a fixed-to-floating interest rate swap at NU parent to manage the interest rate risk associated with its $263 million of fixed-rate long-term debt.

Credit Risk Management: Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of our contractual obligations. We serve a wide variety of customers and suppliers that include independent power producers (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 which, in turn, require us to manage the portfolio of market risk inherent in those transactions in a manner consistent with the parameters established by our risk management process.

Credit risks and market risks at NU Enterprises are monitored regularly by a Risk Oversight Council. The Risk Oversight Council is comprised of individuals from outside of the management of these activities that create these risk exposures and functions to ensure compliance with our stated risk management policies.

We track and re-balance the risk in our portfolio in accordance with fair value and other risk management methodologies that utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

The NYMEX traded futures and option contracts cleared off the NYMEX exchange are ultimately guaranteed by NYMEX to Select Energy. Select Energy has established written credit policies with regard to its counterparties to minimize overall credit risk on all types of transactions. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash in advance, LOCs, and parent guarantees), and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in establishing credit limits prior to Select Energy entering into energy contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may impact Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes to economic, regulatory or other conditions.

At December 31, 2007, Select Energy had collateral balances deposited with counterparties of $18.9 million, which is included in current assets - prepayments and other on the accompanying condensed consolidated balance sheets. There were no such deposits as of June 30, 2008. At June 30, 2008, balances collected from counterparties resulting from Select Energy's credit management activities totaled $6.4 million, which is included in current liabilities - other on the accompanying condensed consolidated balance sheets. There were no such balances as of December 31, 2007.

Our regulated companies are subject to credit risk from certain long-term or high-volume supply contracts with energy marketing companies. Our regulated companies manage the credit risk with these counterparties in accordance with established credit risk practices and maintain an oversight group that monitors contracting risks, including credit risk.

We have implemented an Enterprise Risk Management (ERM) methodology for identifying the principal risks of the company. ERM involves the application of a well-defined, enterprise-wide methodology that will enable our Risk and Capital Committee, comprised of our senior officers, to oversee the identification, management and reporting of the principal risks of the business. However, there can be no assurances that the ERM process will identify every risk or event that could impact our financial condition or results of operations. The findings of this process are periodically discussed with our Board of Trustees.

Additional quantitative and qualitative disclosures about market risk are set forth in Part I, Item 2, "Management's Discussion and Analysis of Financial Condition and Results of Operations," included in this combined report on Form 10-Q.

ITEM 4.

CONTROLS AND PROCEDURES

NU evaluated the design and operation of its disclosure controls and procedures at June 30, 2008 to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Exchange Act and the rules and regulations of the SEC. This evaluation was made under the supervision and with the participation of management, including NU s principal executive officer and principal financial officer, as of the end of the period covered by this report on Form 10-Q. The principal executive officer and principal financial officer have concluded, based on their review, that NU s disclosure controls and procedures are effective to ensure that information required to be disclosed by NU in reports that it files under the Exchange Act (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 officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no changes in internal controls over financial reporting for NU during the quarter ended June 30, 2008 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 Annual Report on Form 10-K for the year ended December 31, 2007. There have been no material changes with regard to the legal proceedings previously disclosed in our most recent Form 10-K, as modified by our disclosure under Item 1, "Legal Proceedings" in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.

ITEM 1A.

RISK FACTORS

NU is 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 - Other Matters." We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2007. NU s susceptibility to certain risks, including those discussed in detail in our Annual Report on Form 10-K, could exacerbate other risks. These risk factors should be considered carefully in evaluating NU s risk profile. There have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K.

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 common stock during the quarter ended June 30, 2008.

ITEM 4.

SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the Annual Meeting of Shareholders of NU held on May 13, 2008, the following twelve nominees were elected to serve on the Board of Trustees by the votes set forth below:

		For	Withheld	Total
1.	Richard M. Booth	129,311,675	2,215,178	131,526,853
2.	John S. Clarkeson	129,119,827	2,407,026	131,526,853
3.	Cotton M. Cleveland	121,813,909	9,712,944	131,526,853
4.	Sanford Cloud, Jr.	129,311,494	2,215,359	131,526,853
5.	James F. Cordes	129,381,529	2,145,324	131,526,853
6.	E. Gail de Planque	128,018,467	3,508,386	131,526,853
7.	John G. Graham	129,336,366	2,190,487	131,526,853
8.	Elizabeth T. Kennan	128,534,094	2,992,759	131,526,853
9.	Kenneth R. Leibler	129,256,587	2,270,266	131,526,853
10.	Robert E. Patricelli	128,745,531	2,781,322	131,526,853
11.	Charles W. Shivery	128,762,772	2,764,081	131,526,853
12.	John F. Swope	128,784,128	2,742,725	131,526,853

NU's shareholders also ratified the Board of Trustees' selection of Deloitte & Touche LLP to serve as independent auditors of NU and its subsidiaries for 2008. The vote ratifying such selection was 130,681,371 votes in favor and 472,802 votes against, with 372,680 abstentions.

CL&P: In a written Consent in Lieu of an Annual Meeting of Stockholders of CL&P dated June 18, 2008, (CL&P Consent) the sole stockholder voted to fix the number of directors for the ensuing year at four and the following four directors were elected to serve on the Board of Directors for the ensuing year: David R. McHale, Raymond P. Necci, Leon J. Olivier and Charles W. Shivery. The vote on each of these proposals was 6,035,205 shares in favor, representing 100 percent of the issued and outstanding shares of common stock of CL&P.

WMECO: In a written Consent in Lieu of an Annual Meeting of Stockholders of WMECO dated June 18, 2008 (WMECO Consent), the sole stockholder voted to fix the number of directors for the ensuing year at four and the following four directors were elected to serve on the Board of Directors for the ensuing year: David R. McHale, Leon J. Olivier, Rodney O. Powell and Charles W. Shivery. The vote on each of these proposals was 434,653 shares in favor, representing 100 percent of the issued and outstanding shares of common stock of WMECO.

PSNH: In a written Consent in Lieu of an Annual Meeting of Stockholders of PSNH dated June 18, 2008 (PSNH Consent), the sole stockholder voted to fix the number of directors for the ensuing year at four and the following four directors were elected to serve on the Board of Directors for the ensuing year: Gary A. Long, David R. McHale, Leon J. Olivier and Charles W. Shivery. The vote on each of these proposals was 301 shares in favor, representing 100 percent of the issued and outstanding shares of common stock of PSNH.

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)

4

Supplemental Indenture, dated as of June 1, 2008 between Northeast Utilities and The Bank of New York Trust Company, N.A., as Trustee relating to $250 million of Senior Notes, Series C, Due 2013 (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated June 5, 2008, File No. 001-5324)

*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 6, 2008

*31.1

Certification of David R. McHale, Senior 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 6, 2008

*32

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities and David R. McHale, Senior 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 6, 2008

Listing of Exhibits (CL&P)

4

Supplemental Indenture, dated as of May 1, 2008 to Indenture of Mortgage and Deed of Trust Dated as of May 1, 1921, as Amended and Restated as of April 7, 2005 by and between The Connecticut Light and Power Company and Deutsche Bank Trust Company Americas, as Trustee, relating to $300 million of 5.65% First and Refunding Mortgage Bonds, 2008 Series A, due 2018 (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated May 27, 2008, File No. 0-00404)

*4.1

Termination Agreement dated as of June 30, 2008, terminating the Amended and Restated Receivables Purchase and Sale Agreement among CL&P Receivables Corporation, CAFCO, LLC, Citibank, N.A., Citicorp North America, Inc., as Agent, and The Connecticut Light and Power Company

*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 6, 2008

*31.1

Certification of David R. McHale, Senior 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 6, 2008

*32

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company and David R. McHale, Senior 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 6, 2008

Listing of Exhibits (PSNH)

*3

By-laws of PSNH, as in effect June 27, 2008

4

Sixteenth Supplemental Indenture, dated as of May 1, 2008, between PSNH and U.S. Bank National Association, Trustee, supplementing the First Mortgage Indenture, dated as of August 15, 1978, between the Company and U.S. Bank National Association as Trustee, relating to $110,000,000 its 6.00% First Mortgage Bonds, Series O, due 2018, (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated May 27, 2008 (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 6, 2008

*31.1

Certification of David R. McHale, Senior 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 6, 2008

*32

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire and David R. McHale, Senior 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 6, 2008

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 6, 2008

*31.1

Certification of David R. McHale, Senior 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 6, 2008

*32

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company and David R. McHale, Senior 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 6, 2008

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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	August 6, 2008
	(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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	August 6, 2008
	(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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	August 6, 2008
	(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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	August 6, 2008
	(for the Registrant and as Principal Financial Officer)	