NORTHEAST UTILITIES
Form 10-Q
August 07, 2007

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, 2007

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)	02-0181050

Energy Park
780 North Commercial Street
Manchester, New Hampshire 03101-1134
Telephone: (603) 669-4000

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

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
√	

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

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

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

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, 2007
Northeast Utilities Common stock, $5.00 par value	154,899,155 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 meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and therefore filed their 2006 Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

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:

CL&P	The Connecticut Light and Power Company
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, 2007, NU Enterprises, Inc., is comprised of Select Energy, NGS, the E.S. Boulos Company (Boulos), the Connecticut division of SECI (SECI-CT) and NU Enterprises parent. For further information, see Note 10, "Segment Information," to the condensed consolidated financial statements.
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 and Yankee Gas, which is a natural gas local distribution company. 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
CTA	Competitive Transition Assessment
COLA	Cost of Living Adjustment
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FMCC	Federally Mandated Congestion Cost
GSC	Generation Service Charge
ISO-NE	New England Independent System Operator
KWH	Kilowatt-Hour
KV	Kilovolt
LOCs	Letters of Credit
MW	Megawatt/Megawatts
NU 2006 Form 10-K	The Northeast Utilities and Subsidiaries combined 2006 Form 10-K as filed with the SEC
NYMEX	New York Mercantile Exchange
OCC	Connecticut Office of Consumer Counsel
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation segments excluding the wholesale transmission segment.
RMR	Reliability Must Run
ROE	Return on Equity
RTO	Regional Transmission Organization
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SFAS	Statement of Financial Accounting Standards
TCAM	Transmission Cost Adjustment Mechanism
TSO	Transitional Standard Offer

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

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

		June 30, 2007	December 31, 2006
		(Thousands of Dollars)	
ASSETS			
Current Assets:			
Cash and cash equivalents	$	138,823	$ 481,911
Special deposits		32,050	48,524
Investments in securitizable assets		343,891	375,655
Receivables, less provision for uncollectible accounts of $20,041 in 2007 and $22,369 in 2006		309,985	361,201
Unbilled revenues		76,734	88,170
Taxes receivable		7,815	-
Fuel, materials and supplies		186,017	173,882
Marketable securities - current		66,090	67,546
Derivative assets - current		107,976	88,857
Prepayments and other		36,241	45,305
		1,305,622	1,731,051
Property, Plant and Equipment:			
Electric utility		7,263,323	7,129,526
Gas utility		933,578	858,961
Other		309,463	299,389
		8,506,364	8,287,876
Less: Accumulated depreciation: $2,448,825 for electric and gas utility and $175,672 for other in 2007;			

$2,440,544 for electric and gas utility and				
$174,562 for other in 2006		2,624,497		2,615,106
		5,881,867		5,672,770
Construction work in progress		763,677		569,416
		6,645,544		6,242,186
Deferred Debits and Other Assets:				
Regulatory assets		2,212,004		2,449,132
Goodwill		287,591		287,591
Prepaid pension		105,376		21,647
Marketable securities - long-term		58,143		50,843
Derivative assets - long-term		283,399		271,755
Other		228,071		249,031
		3,174,584		3,329,999
Total Assets	$	11,125,750	$	11,303,236

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2007	December 31, 2006
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Long-term debt - current portion	$ 154,286	$ 4,877
Accounts payable	505,242	569,940
Accrued taxes	-	364,659
Accrued interest	63,265	53,782
Derivative liabilities - current	99,188	125,843
Counterparty deposits	2,600	148
Other	241,760	244,586
	1,066,341	1,363,835
Rate Reduction Bonds	1,067,403	1,177,158
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,051,114	1,099,433
Accumulated deferred investment tax credits	30,636	32,427
Deferred contractual obligations	248,039	271,528
Regulatory liabilities	875,780	809,324
Derivative liabilities - long-term	114,125	148,557
Accrued postretirement benefits	189,927	203,320
Other	390,330	322,840
	2,899,951	2,887,429
Capitalization:		

Long-Term Debt	3,152,753	2,960,435
Preferred Stock of Subsidiary - Non-Redeemable	116,200	116,200
Common Shareholders' Equity:		
Common shares, $5 par value - authorized		
225,000,000 shares; 175,895,458 shares issued		
and 154,856,609 shares outstanding in 2007 and		
175,420,239 shares issued and 154,233,141 shares		
outstanding in 2006	879,477	877,101
Capital surplus, paid in	1,460,851	1,449,586
Deferred contribution plan - employee stock		
ownership plan	(30,846)	(34,766)
Retained earnings	864,598	862,660
Accumulated other comprehensive income	10,549	4,498
Treasury stock, 19,705,353 shares in 2007		
and 19,684,249 shares in 2006	(361,527)	(360,900)
Common Shareholders' Equity	2,823,102	2,798,179
Total Capitalization	6,092,055	5,874,814
Commitments and Contingencies (Note 6)		
Total Liabilities and Capitalization	$ 11,125,750	$ 11,303,236

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

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 1,392,053	$ 1,661,061	$ 3,096,346	$ 3,808,449
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	804,802	1,109,671	1,875,288	2,653,701
Other	245,643	268,583	483,778	578,315
Restructuring and impairment charges	-	3,282	193	8,425
Maintenance	59,848	49,200	105,845	87,621
Depreciation	63,420	59,656	126,889	118,485
Amortization	(3,453)	(1,078)	2,770	57,394
Amortization of rate reduction bonds	47,114	43,997	98,913	92,675
Taxes other than income taxes	57,360	54,442	129,950	130,867
Total operating expenses	1,274,734	1,587,753	2,823,626	3,727,483
Operating Income	117,319	73,308	272,720	80,966
Interest Expense:				
Interest on long-term debt	40,234	34,250	76,447	67,821
Interest on rate reduction bonds	15,839	18,982	32,189	38,863
Other interest	3,451	7,626	10,154	13,626
Interest expense, net	59,524	60,858	118,790	120,310
Other Income, Net	11,873	12,159	25,942	26,363
Income/(Loss) from Continuing Operations				

Before Income Tax Expense/(Benefit)	69,668	24,609	179,872	(12,981)
Income Tax Expense/(Benefit)	22,086	8,920	54,664	(9,385)
Income/(Loss) from Continuing Operations Before Preferred Dividends of Subsidiary	47,582	15,689	125,208	(3,596)
Preferred Dividends of Subsidiary	1,389	1,389	2,779	2,779
Income/(Loss) from Continuing Operations	46,193	14,300	122,429	(6,375)
Discontinued Operations (Note 3):				
Income from Discontinued Operations	-	20,364	-	38,847
Gains/(Losses) from Sale/Disposition of Discontinued Operations	3,925	(5,578)	2,017	(6,478)
Income Tax Expense	1,565	6,844	799	13,858
Income from Discontinued Operations	2,360	7,942	1,218	18,511
Net Income	$ 48,553	$ 22,242	$ 123,647	$ 12,136
Basic and Fully Diluted Earnings/(Loss) Per Common Share:				
Income/(Loss) from Continuing Operations	$ 0.30	$ 0.09	$ 0.79	$ (0.04)
Income from Discontinued Operations	0.01	0.05	0.01	0.12
Basic and Fully Diluted Earnings Per Common Share	$ 0.31	$ 0.14	$ 0.80	$ 0.08
Basic Common Shares Outstanding (weighted average)	154,729,676	153,628,709	154,539,678	153,535,675
Fully Diluted Common Shares Outstanding (weighted average)	155,213,094	153,922,635	155,102,672	153,809,133

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,	
	2007	2006
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 123,647	$ 12,136
Adjustments to reconcile to net cash flows (used in)/provided by operating activities:		
Bad debt expense	12,917	21,181
Depreciation	126,889	121,445
Deferred income taxes	(10,158)	168,525
Amortization	2,770	57,394
Amortization of rate reduction bonds	98,913	92,675
Amortization/(deferral) of recoverable energy costs	6,248	(7,616)
Pension expense, net of capitalized portion	10,388	18,454
Regulatory overrecoveries/(refunds)	64,174	(141,968)
Derivative assets and liabilities	(36,830)	(57,102)
Deferred contractual obligations	(23,489)	(50,282)
Other non-cash adjustments	(2,989)	(20,545)
Other sources of cash	-	22,147
Other uses of cash	(35,019)	(5,548)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	56,248	543,368
Fuel, materials and supplies	(12,135)	33,108
Investments in securitizable assets	17,674	(19,330)
Other current assets	7,177	11,664
Accounts payable	(67,312)	(408,632)

Counterparty deposits and margin special deposits		18,926		63,299
Taxes receivable and accrued taxes		(372,867)		(220,875)
Other current liabilities		(22,672)		(20,351)
Net cash flows (used in)/provided by operating activities		(37,500)		213,147
Investing Activities:				
Investments in property and plant		(491,137)		(380,703)
Cash payments related to the sale of competitive businesses		(1,908)		(19,429)
Proceeds from sales of investment securities		101,113		84,695
Purchases of investment securities		(103,902)		(79,903)
Other investing activities		10,517		(989)
Net cash flows used in investing activities		(485,317)		(396,329)
Financing Activities:				
Issuance of common shares		8,520		4,068
Issuance of long-term debt		345,000		250,000
Retirement of rate reduction bonds		(109,755)		(103,327)
Increase in short-term debt		-		99,000
Reacquisitions and retirements of long-term debt		(4,877)		(10,631)
Cash dividends on common shares		(58,502)		(54,025)
Other financing activities		(657)		1,059
Net cash flows provided by financing activities		179,729		186,144
Net (decrease)/increase in cash and cash equivalents		(343,088)		2,962
Cash and cash equivalents - beginning of period		481,911		45,782
Cash and cash equivalents - end of period	$	138,823	$	48,744

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 this Form 10-Q in its entirety 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 as part of the Northeast Utilities and subsidiaries combined 2006 Form 10-K (NU 2006 Form 10-K) with the SEC. 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, 2007, the results of operations for the three and six months ended June 30, 2007 and 2006 and cash flows for the six months ended June 30, 2007 and 2006. The results of operations and statements of cash flows for the six months ended June 30, 2007 and 2006 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 presentation. For the three and six months ended June 30, 2006, wholesale contract market changes, net were separately stated on the condensed consolidated statements of income to increase the transparency of the mark-to-market related to Select Energy Inc.'s (Select Energy) wholesale marketing portfolio. As the disclosure of this amount is currently not as meaningful as it was in prior periods, $12.9 million and $19.7 million have been reclassified to fuel, purchased and net interchange power on the accompanying condensed consolidated statements of income for the three and six months ended June 30, 2006, respectively. For further information regarding Select Energy's derivatives, see Note 4, "Derivative Instruments," to the condensed consolidated financial statements.

In NU's, CL&P's, PSNH's and WMECO's condensed consolidated statements of income for the three and six months ended June 30, 2006, the classification of certain cost and income items previously included in other income, net and interest expense was changed to operating expenses. In addition, revenues were also reclassified to operating expenses as a result of the change in classification of certain revenues and associated expenses from a gross presentation to a net presentation. These changes for NU, CL&P, PSNH and WMECO for the three and six months ended June 30, 2006 are as follows:

	Three Months Ended June 30, 2006				**Six Months Ended June 30, 2006**			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Decrease in operating revenues	$ (9.5)	$ (0.5)	$ (8.8)	$ (0.1)	$ (9.5)	$ (0.5)	$ (8.8)	$ (0.1)
Decrease/(increase) in operating expenses	$ 7.5	$ (1.5)	$ 8.5	$ 0.4	$ 6.5	$ (1.8)	$ 8.1	$ 0.4
Decrease in interest expense	$ 2.5	$ 2.5	$ -	$ -	$ 4.7	$ 4.7	$ -	$ -
(Decrease)/increase in other income	$ (0.5)	$ (0.5)	$ 0.3	$ (0.3)	$ (1.7)	$ (2.4)	$ 0.7	$ (0.3)

These reclassifications had no impact on the companies' results of operations, financial condition or cash flows.

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NU's condensed consolidated statements of income for the three and six months ended June 30, 2006 classifies the past operations for the following as discontinued operations:

- Northeast Generation Company (NGC), including certain components of Northeast Generation Services Company (NGS),
- The Mt. Tom generating plant (Mt. Tom) previously owned by Holyoke Water Power Company (HWP),
- Select Energy Services, Inc. (SESI) and its wholly owned subsidiaries HEC/Tobyhanna Energy Project, Inc. and HEC/CJTS Energy Center LLC, and
- A portion of the former Woods Electrical Co., Inc. (Woods Electrical).

For further information regarding these companies, see Note 3, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements.

B.

Accounting Standards Issued But Not Yet Adopted

Fair Value Measurements: On September 15, 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is expected to be applied to fair value measurements of derivative contracts that are subject to mark-to-market accounting and to other assets and liabilities that are reported at fair value or subject to fair value measurements. SFAS No. 157 is expected to be implemented prospectively with any adjustments to fair value reflected as a cumulative effect adjustment to the opening balance of retained earnings as of January 1, 2008. The company is evaluating the potential impact of SFAS No. 157 on its financial statements.

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in earnings. The company is evaluating the measurement options available under SFAS No. 159, which will be effective in the first quarter of 2008.

C.

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 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 Services Company's (Yankee Gas) 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 the 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, which are not supported by equity. Amortization and deferrals of regulatory assets 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, 2007				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Securitized assets	$ 1,020.8	$ 628.9	$ 300.0	$ 91.9	$ -
Deferred benefit costs	313.0	103.2	76.9	15.2	117.7
Income taxes, net	295.8	266.6	-	29.0	0.2
Unrecovered contractual obligations	203.8	157.3	-	46.5	-
CTA and SBC undercollections	97.5	97.5	-	-	-
Regulatory assets offsetting regulated company derivative liabilities	47.8	30.7	17.1	-	-

Other regulatory assets		233.3		50.7		90.2		32.0		60.4
Totals	$	2,212.0	$	1,334.9	$	484.2	$	214.6	$	178.3

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	At December 31, 2006				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Securitized assets	$ 1,131.1	$ 707.2	$ 325.6	$ 98.3	$ -
Deferred benefit costs	407.4	155.8	90.4	25.8	135.4
Income taxes, net	308.0	266.6	5.5	41.3	(5.4)
Unrecovered contractual obligations	214.4	163.7	-	50.7	-
CTA and SBC undercollections	100.5	100.5	-	-	-
Regulatory assets offsetting regulated company derivative liabilities	75.4	36.0	39.2	-	0.2
Other regulatory assets	212.3	47.6	63.8	36.2	64.7
Totals	$ 2,449.1	$ 1,477.4	$ 524.5	$ 252.3	$ 194.9

Included in NU's other regulatory assets are the regulatory assets associated with the implementation of FASB Interpretation (FIN) 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $50 million at June 30, 2007 and $46.4 million at December 31, 2006. Of these amounts, $13.9 million and $13.7 million, respectively, have been approved for future recovery. At this time, management believes that the remaining regulatory assets are also probable of recovery.

For information regarding the cost of living adjustment (COLA) and the decrease in the deferred benefit costs regulatory assets, see Note 9, "Pension Benefits and Postretirement Benefits Other Than Pensions," to the condensed consolidated financial statements.

The companies above had $13.2 million and $11.2 million of costs at June 30, 2007 and December 31, 2006, respectively, that are included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets. These amounts represent costs that have not yet been approved by the applicable regulatory agency. Management believes these assets are recoverable in future cost of service regulated rates.

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

	At June 30, 2007				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Cost of removal	$ 282.0	$ 128.1	$ 77.7	$ 24.0	$ 52.2
Regulatory liabilities offsetting regulated company derivative assets	326.1	325.2	0.9	-	-
Generation service charge/FMCC overcollections	129.8	129.8	-	-	-
Other regulatory liabilities	137.9	57.1	40.6	10.9	29.3
Totals	$ 875.8	$ 640.2	$ 119.2	$ 34.9	$ 81.5

	At December 31, 2006				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Cost of removal	$ 290.8	$ 134.4	$ 79.2	$ 23.6	$ 53.6
Regulatory liabilities offsetting regulated company derivative assets	294.5	294.5	-	-	-
Generation service charge/FMCC overcollections	108.2	108.2	-	-	-
Other regulatory liabilities	115.8	45.7	36.5	3.2	30.4
Totals	$ 809.3	$ 582.8	$ 115.7	$ 26.8	$ 84.0

For information regarding derivative assets, see Note 4, "Derivative Instruments," to the 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 cost of equity funds is recorded as other income on the accompanying condensed consolidated statements of income, as follows:

	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars, except percentages)	June 30, 2007	June 30, 2006	June 30, 2007	June 30, 2006
Borrowed funds	$ 4.3	$ 3.2	$ 8.6	$ 6.1
Equity funds	4.0	2.6	6.3	6.3
Totals	$ 8.3	$ 5.8	$ 14.9	$ 12.4
Average AFUDC rates	7.5%	6.9%	7.2%	7.1%

The regulated companies' average AFUDC rate is based on a Federal Energy Regulatory Commission (FERC) prescribed formula that develops 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 transmission incentives.

E.

Income Taxes

Effective on January 1, 2007, NU implemented FIN 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." FIN 48 applies to all tax positions previously filed in a tax return and tax positions expected to be taken in a future tax return that have been reflected on the balance sheets. FIN 48 addresses the methodology to be used prospectively in recognizing, measuring and classifying the amounts associated with tax positions that are deemed to be uncertain, including related interest and penalties. Previously, NU recorded estimates for uncertain tax positions in accordance with SFAS No. 5, "Accounting for Contingencies."

As a result of implementing FIN 48, NU recognized a cumulative effect of a change in accounting principle of $32.5 million as a reduction to the January 1, 2007 balance of retained earnings. The CL&P, PSNH and WMECO reductions/(benefits) to the January 1, 2007 balances of retained earnings were $15.6 million, $(1.6) million and $(0.4) million, respectively.

Interest and Penalties: Effective on January 1, 2007, NU s accounting policy for the classification of interest and penalties related to FIN 48 was as follows:

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Interest on uncertain tax positions is recorded and classified as a component of other interest expense. NU recorded accrued interest expense of $17.4 million, which is included in the cumulative effect of a change in accounting principle as of January 1, 2007. NU recorded accrued interest expense of $1.8 million and $3.8 million for the three and six months ended June 30, 2007, respectively.

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No penalties have been recorded under FIN 48. If penalties are recorded in the future, then the estimated penalties would be classified as a component of other income/expense.

Unrecognized Tax Benefits: Upon adoption of FIN 48 on January 1, 2007, NU recorded a liability for unrecognized tax benefits totaling $73.5 million, of which $56.9 million would impact the effective tax rate, if recognized. As of June 30, 2007, NU's liability for unrecognized tax liabilities totaled $82 million, of which $65.4 million would impact the effective tax rate, if recognized.

Tax Positions: NU is currently undergoing tax audits, and it is reasonably possible as these audits progress that the liability for unrecognized tax benefits could change significantly in the next 12 months; however, management cannot estimate the amount of change at this time.

Tax Years: The following table summarizes NU's tax years that remain subject to examination by major tax jurisdictions at January 1, 2007:

Description	Tax Years
Federal	2002 - 2006
Connecticut	1997 - 2006
New Hampshire	2003 - 2006
Massachusetts	2003 - 2006

F.

Sale of Customer Receivables

CL&P Receivables Corporation (CRC), a consolidated, wholly-owned subsidiary of CL&P, can sell up to $100 million of an undivided interest in its accounts receivable and unbilled revenues to a financial institution. At June 30, 2007 and December 31, 2006, there were no such sales.

At June 30, 2007 and December 31, 2006, amounts sold to CRC by CL&P but not sold to the financial institution totaling $343.9 million and $375.7 million, respectively, are included in investments in securitizable assets on the accompanying condensed consolidated balance sheets. These amounts would be excluded from CL&P's assets in the event of CL&P's bankruptcy.

On July 3, 2007, CL&P extended the bank commitment under the Receivables Purchase and Sale Agreement with CRC and the financial institution through June 30, 2008 and extended the facility termination date to June 21, 2012. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to servicing those receivables.

The transfer of receivables to the financial institution under this arrangement qualifies for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities - A Replacement of SFAS No. 125."

G.

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, overdraft amounts are reclassified from cash and cash equivalents to accounts payable.

H.

Special Deposits and Counterparty Deposits

To the extent Select Energy requires collateral from counterparties, or the counterparties require collateral from Select Energy, cash is paid to or by Select Energy 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 $32.1 million and $48.5 million at June 30, 2007 and December 31, 2006, respectively. These amounts are recorded as current assets and are included as special deposits on the accompanying condensed consolidated balance sheets.

Balances collected from counterparties resulting from Select Energy s credit management activities totaled $2.6 million and $0.1 million at June 30, 2007 and December 31, 2006, respectively. These amounts are recorded as current liabilities and are included as counterparty deposits on the accompanying condensed consolidated balance sheets.

The company also had amounts on deposit related to four special purpose entities used to facilitate the issuance of rate reduction bonds and certificates. These amounts, which totaled $96.1 million and $102.5 million at June 30, 2007 and December 31, 2006, respectively, are included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets.

I.

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, 2007**	**June 30, 2006**	**June 30, 2007**	**June 30, 2006**
Other Income:				
Investment income	$ 5.9	$ 1.0	$ 14.4	$ 8.0
Gain on sale of investment in Globix	-	3.1	-	3.1
CL&P procurement fee	-	2.6	-	5.5
AFUDC - equity funds	4.0	2.6	6.3	6.3
Energy Independence Act incentives	2.2	2.5	4.9	2.5
Other	0.4	0.5	0.9	1.1
Total Other Income	$ 12.5	$ 12.3	$ 26.5	$ 26.5
Other Loss:				
Investment write-down	(0.5)	-	(0.5)	-
Other	(0.1)	(0.1)	(0.1)	(0.1)
Total Other Loss	$ (0.6)	$ (0.1)	$ (0.6)	$ (0.1)
Total Other Income, Net	$ 11.9	$ 12.2	$ 25.9	$ 26.4

CL&P	**For the Three Months Ended**		**For the Six Months Ended**	
(Millions of Dollars)	**June 30, 2007**	**June 30, 2006**	**June 30, 2007**	**June 30, 2006**
Other Income:				
Investment income	$ 1.6	$ (0.5)	$ 3.0	$ 3.0
CL&P procurement fee	-	2.6	-	5.5
AFUDC - equity funds	2.9	1.0	4.4	3.5
Energy Independence Act incentives	2.2	2.5	4.9	2.5
Other	0.2	0.1	0.5	0.6
Total Other Income	$ 6.9	$ 5.7	$ 12.8	$ 15.1
Other Loss	$ -	$ -	$ (0.1)	$ (0.1)
Total Other Income, Net	$ 6.9	$ 5.7	$ 12.7	$ 15.0

PSNH	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars)	June 30, 2007	June 30, 2006	June 30, 2007	June 30, 2006
Other Income:				
Investment income	$ 0.2	$ 0.2	$ 0.4	$ 0.4
AFUDC - equity funds	0.5	1.2	0.9	2.3
Other	-	-	0.1	0.1
Total Other Income	$ 0.7	$ 1.4	$ 1.4	$ 2.8

WMECO	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars)	June 30, 2007	June 30, 2006	June 30, 2007	June 30, 2006
Other Income:				
Investment income	$ 0.3	$ (0.2)	$ 0.6	$ 0.1
Conservation and load management incentive	0.1	0.2	0.3	0.7
Total Other Income	$ 0.4	$ -	$ 0.9	$ 0.8

Investment income for NU includes equity in earnings/(losses) of regional nuclear generating and transmission companies of $0.4 million and $(2.2) million for the three months ended June 30, 2007 and 2006, respectively, and $1.1 million and $(1.2) million for the six months ended June 30, 2007 and 2006, respectively. Equity in earnings relates to the company's investment in the Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company, Yankee Atomic Electric Company and the Hydro-Quebec transmission system.

Based on developments in July of 2006, CYAPC management concluded that $10 million of CYAPC's regulatory assets were no longer probable of recovery and should be written off. Because the contingency surrounding these regulatory assets existed at June 30, 2006, the write-off was recorded in the second quarter of 2006. NU recorded a total after-tax write-off of $3 million ($2.1 million, $0.3 million and $0.6 million for CL&P, PSNH and WMECO, respectively) for its ownership share of this charge, which is included in investment income in the tables above.

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, 2007 and 2006, gross receipts taxes, franchise taxes and other excise taxes of $26.3 million and $58 million, respectively, for 2007 and $26.6 million and $57.8 million, respectively, for 2006, are included in operating revenues and taxes other than income taxes on the accompanying condensed consolidated statements of income. Certain sales taxes are also collected by the regulated companies from their customers as agent for state and local governments and are recorded on a net basis with no impact on the accompanying condensed consolidated statements of income.

K.

Asset Retirement Obligations

In 2006, the Connecticut Department of Public Utility Control (DPUC) initiated a proceeding related to an investigation into various underground electrical network failures on the CL&P system in 2001 and 2006 in Waterbury, Meriden and Stamford, Connecticut. On April 25, 2007, the DPUC issued a final decision finding it necessary for CL&P to replace older type cable in those municipalities. The removal of the older type cable was deemed necessary by CL&P, and as a result, an asset retirement obligation (ARO) was recorded in the second quarter of 2007. At June 30, 2007, the fair value of the ARO asset recorded is $1.4 million, accumulated depreciation is $0.1 million and the ARO liability is $1.4 million. The charge to record $0.1 million of accumulated depreciation and accretion was recorded as a regulatory asset, as management believes that this amount is recoverable in rates.

2.

RESTRUCTURING AND IMPAIRMENT CHARGES (NU, NU Enterprises)

NU Enterprises recorded $0.2 million of pre-tax restructuring and impairment charges for the six months ended June 30, 2007, relating to the decision to exit the competitive businesses. The charges for the three and six months ended June 30, 2006 were $9.5 million and $15.6 million, respectively. The amounts related to continuing operations are included as restructuring and impairment charges on the condensed consolidated statements of income with the remainder included in discontinued operations. These charges are included as part of the NU Enterprises reportable segment in Note 10, "Segment Information." A summary of these pre-tax restructuring and impairment charges is as follows:

(Millions of Dollars)	For the Three Months Ended June 30, 2007	June 30, 2006	For the Six Months Ended June 30, 2007	June 30, 2006
Wholesale Marketing:				
Restructuring charges	$ -	$ 0.6	$ -	$ 0.6
Retail Marketing:				
Restructuring charges	-	0.8	-	5.5
Competitive Generation:				
Impairment charges	-	0.3	-	0.3
Restructuring charges	-	0.9	-	2.6
Subtotal	$ -	$ 1.2	$ -	$ 2.9
Energy Services and Other:				
Impairment charges	$ -	$ 0.1	$ -	$ 0.1
Restructuring charges	-	6.8	0.2	6.5
Subtotal	$ -	$ 6.9	$ 0.2	$ 6.6
Total restructuring and impairment charges	$ -	$ 9.5	$ 0.2	$ 15.6
Restructuring and impairment charges included in discontinued operations	$ -	$ 6.2	$ -	$ 7.2
Total restructuring and impairment charges included in continuing operations	$ -	$ 3.3	$ 0.2	$ 8.4

Restructuring charges totaling $0.2 million for six months ended June 30, 2007, were recorded for energy services and other related to consulting fees, legal fees, employee-related and other costs incurred.

In the second quarter and first half of 2006, $0.6 million of restructuring charges were recorded for wholesale marketing for consulting fees, legal fees, employee-related and other costs.

On June 1, 2006, NU Enterprises completed the sale of Select Energy New York, Inc. (SENY). In connection with the closing of this transaction, NU Enterprises recorded restructuring charges of $0.3 million for retail marketing, which is included in restructuring and impairment charges on the accompanying condensed consolidated statements of income for the three and six months ended June 30, 2006. In addition to the $0.3 million charge, restructuring charges of $0.5 million and $5.2 million were recorded in the first quarter and first half of 2006, respectively, for consulting fees, legal fees, employee-related and other costs.

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In the second quarter and first half of 2006, $0.3 million of impairments were recorded for competitive generation related to certain long-lived assets of NGS that were no longer recoverable and were written off. Restructuring charges of $0.9 million and $2.6 million were recorded in the first quarter and first half of 2006 for consulting fees, legal fees, employee-related and other costs.

On May 5, 2006, NU Enterprises completed the sale of SESI. In connection with the closing of this transaction, NU Enterprises recorded a pre-tax restructuring charge of $5.6 million in the second quarter of 2006 for energy services and other, which is included in loss from sale of discontinued operations on the accompanying condensed consolidated statements of income. In addition to the $5.6 million second quarter charge, a restructuring charge of $0.9 million was recorded in the first quarter of 2006, resulting in a $6.5 million loss from sale of discontinued operations recorded in the first half of 2006. In addition to these charges, restructuring charges of $1.2 million and $1.7 million were recorded in the first quarter and first half of 2006 for consulting fees, legal fees, employee-related costs and other costs. Offsetting the first half loss is a restructuring benefit of $1.7 million from the gain on the sale of Massachusetts service location of Select Energy Contracting, Inc. - Connecticut (SECI-CT).

The following table summarizes the liabilities related to restructuring costs which are recorded in accounts payable and other current liabilities on the accompanying condensed consolidated balance sheets at June 30, 2007 and December 31, 2006:

(Millions of Dollars)	**Employee-Related Costs**	**Professional and Other Fees**	**Total**
Restructuring liability as of January 1, 2005	$ -	$ -	$ -
Costs incurred	2.3	7.4	9.7
Cash payments and other deductions/reversals	(0.5)	(3.2)	(3.7)
Restructuring liability as of December 31, 2005	1.8	4.2	6.0
Costs incurred	3.3	24.0	27.3
Cash payments and other deductions/reversals	(3.7)	(25.9)	(29.6)
Restructuring liability as of December 31, 2006	1.4	2.3	3.7
Costs incurred	-	0.2	0.2
Cash payments and other deductions/reversals	(1.0)	(1.2)	(2.2)
Restructuring liability as of March 31, 2007	0.4	1.3	1.7
Costs incurred	-	-	-

Cash payments and other deductions/reversals	(0.2)		-	(0.2)
Restructuring liability as of June 30, 2007	$ 0.2		$ 1.3	$ 1.5

3.

ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS (NU, NU Enterprises)

Assets Held for Sale: In the first quarter of 2006, management determined that the retail marketing and competitive generation businesses met held for sale criteria under applicable accounting guidance, and should be recorded at the lower of their carrying amount or fair value less cost to sell. The retail marketing business was reduced to its fair value less cost to sell through an approximately $53 million pre-tax charge for the six months ended June 30, 2006, which was recorded in other operating expenses.

At June 30, 2007, management continues to believe that the remaining wholesale marketing business, NGS, Boulos, and SECI-CT do not meet the held for sale criteria under applicable accounting guidance and therefore continue to be held and used and included in continuing operations.

Discontinued Operations: NU's condensed consolidated statements of income present NGC, Mt. Tom, SESI, and Woods Electrical as discontinued operations for all periods presented. These businesses were sold in 2006. Under discontinued operations presentation, revenues and expenses of the businesses classified as discontinued operations are classified net of tax in income from discontinued operations on the condensed consolidated statements of income and all prior periods are reclassified. Summarized financial information for the discontinued operations is as follows:

	For the Three Months Ended		**For the Six Months Ended**	
(Millions of Dollars)	**June 30, 2007**	**June 30, 2006**	**June 30, 2007**	**June 30, 2006**
Operating revenue	$ -	$ 52.6	$ -	$ 111.3
Income before income tax expense	-	20.4	-	38.8
Gains/(losses) on sale/disposition of discontinued operations	3.9	(5.6)	2.0	(6.5)
Income tax expense	1.5	6.8	0.8	13.9
Net income	2.4	7.9	1.2	18.5

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The gains/(losses) on sale/disposition of discontinued operations of $3.9 million for the three months ended June 30, 2007 primarily relates 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 the three and six months ended June 30, 2007. Included in discontinued operations are $48.2 million and $98.3 million for the three and six months ended June 30, 2006 of intercompany revenues that are not eliminated in consolidation due to the separate presentation of discontinued operations. Of the 2006 amounts, $48.3 million and $98.1 million, respectively, represent revenues on intercompany contracts between the generation operations of NGC and Mt. Tom and Select Energy. NGC's and Mt. Tom's revenues and earnings related to these contracts are included in discontinued operations while Select Energy's related and offsetting expenses and losses are included in continuing operations.

Select Energy's obligation to NGC and Mt. Tom ended at the time of the sale of the competitive generation business. See Note 6F, "Commitments and Contingencies - Guarantees and Indemnifications," for information related to an HWP coal purchase contract with a supplier and a related back-to-back agreement with the purchaser of the competitive generation business. At June 30, 2007, NU does not have or expect to have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations.

The retail marketing business is not presented as discontinued operations because separate financial information is not available for this business for all prior periods presented.

In the second quarter of 2007, the remaining contracts of Woods Electrical were completed. The results of these contracts were not material to any of the periods presented and discontinued operations presentation is not required.

4.

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

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 changes in the fair value of the effective portion of those contracts are generally recognized in accumulated other comprehensive income. Cash flow hedges impact net income when the forecasted transaction being hedged occurs, when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is no longer probable of occurring, or when there is accumulated other comprehensive loss and the hedge and the forecasted transaction being hedged are in a loss position on a combined basis. The ineffective portion of contracts that meet the cash flow hedge requirements is recognized currently in earnings. 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 currently 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 change in fair value of a normal purchase or sale contract is not included in earnings.

The tables below summarize current and long-term derivative assets and liabilities at June 30, 2007 and December 31, 2006. The fair value of these contracts may not represent amounts that will be realized. On the accompanying condensed consolidated balance sheets at June 30, 2007 and December 31, 2006, these amounts are recorded as current or long-term derivative assets or liabilities and are summarized as follows:

	At June 30, 2007				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises - Wholesale	$ 56.2	$ 9.1	$ (79.7)	$ (75.2)	$ (89.6)
Regulated Companies - Electric:					
Non-trading	51.8	274.3	(19.5)	(28.3)	278.3
NU Parent:					
Hedging	-	-	-	(10.6)	(10.6)
Totals	$ 108.0	$ 283.4	$ (99.2)	$ (114.1)	$ 178.1

	At December 31, 2006				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises:					
Wholesale	$ 43.6	$ 22.3	$ (82.3)	$ (110.1)	$ (126.5)
Retail	0.2	-	(0.1)	-	0.1
Regulated Companies - Gas:					
Non-trading	0.1	-	(0.2)	-	(0.1)
Regulated Companies - Electric:					
Non-trading	45.0	249.5	(43.2)	(32.0)	219.3
NU Parent:					
Hedging	-	-	-	(6.5)	(6.5)
Totals	$ 88.9	$ 271.8	$ (125.8)	$ (148.6)	$ 86.3

For the regulated companies, offsetting regulatory assets or liabilities are recorded for the changes in fair value of their contracts, as these contracts are part of stranded costs or 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 result in exposures to credit risk to energy marketing and trading counterparties. At June 30, 2007, Select Energy had $65.3 million of derivative assets from wholesale activities that are exposed to counterparty credit risk.

NU Enterprises - Wholesale: Certain electric derivative contracts are part of the remaining wholesale marketing business that the company is in the process of exiting. These contracts include wholesale short-term and long-term electricity supply and sales contracts, which include a contract to sell electricity to a utility under full requirements contracts (four other similar contracts expired May 31, 2007), a contract to sell electricity to an agency that is comprised of municipalities with a term of seven remaining years, and a contract to purchase the output of a generating plant. The fair value of these electricity contracts was determined by prices from external sources for years through 2011 and generally by models based on natural gas prices and a heat-rate conversion factor to electricity for subsequent periods. At June 30, 2007 and December 31, 2006, the net fair value of these wholesale contracts was a liability of $89.6 million and $126.5 million, respectively.

For the three months ended June 30, 2007 and 2006, NU recorded a pre-tax charge of $4.6 million and $11.9 million, respectively, in fuel, purchased and net interchange power related to the wholesale contracts. Similar charge amounts were $2.1 million and $18.7 million for the six months ended June 30, 2007 and 2006, respectively. These charges are associated with the mark-to-market on and changes in the fair value of certain long-dated wholesale electricity contracts in New England, New York and PJM and contracts to purchase generation products in New York. A charge of $1 million was also recorded in fuel, purchased and net interchange power in the second quarter 2006 related to the mark-to-market of certain asset specific sales and forward sales of electricity at hub points for generation contracts.

Regulated Companies - Electric - Non-Trading: CL&P has contracts with two independent power producers (IPP) 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 IPP non-trading derivatives at June 30, 2007 include a derivative asset with a fair value of $322.1 million and a derivative liability with a fair value of $30 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, 2006, the fair values of these IPP non-trading derivatives included a derivative asset with a fair value of $289.6 million and a derivative liability with a fair value of $35.6 million.

CL&P has entered into Financial Transmission Rights 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, 2007, the fair value of these contracts is recorded as a derivative asset of $3.1 million and a derivative liability of $0.7 million on the accompanying condensed consolidated balance sheets. At December 31, 2006, the fair value of those contracts was recorded as a derivative asset of $4.9 million and a derivative liability of $0.4 million on the accompanying condensed consolidated balance sheets.

PSNH has a contract to purchase oil that no longer qualified for the normal purchases and sales exception in the fourth quarter of 2006 due to offsetting sales of oil. This contract is a non-trading derivative at June 30, 2007, the fair value of which is calculated based on market prices and is recorded as a derivative liability of $0.1 million. At December 31, 2006, the fair value is recorded as a derivative liability of $10.8 million. An offsetting regulatory asset was recorded as management believes that this cost will be recovered in rates through a deferral mechanism that tracks generation revenues and costs.

PSNH has electricity procurement contracts that management determined no longer qualified for the normal purchases and sales exception in the fourth quarter of 2006 due to quantities being sold into the energy market. These contracts are non-trading derivatives at June 30, 2007, the fair value of which is calculated based on market prices and is recorded as a derivative liability of $17 million. At December 31, 2006, the fair value is recorded as a derivative liability of $28.4 million. An offsetting regulatory asset was recorded as management believes that these costs will be recovered in rates as the energy is delivered.

In 2007, PSNH entered into a contract to assign transmission rights of a Hydro-Quebec direct current line in exchange for two energy call options. These energy call options are derivatives that do not qualify for the normal purchases and sales exception and are accounted for at fair value calculated based on market prices. At June 30, 2007, the options are recorded as a derivative asset of $0.9 million. An offsetting regulatory liability was recorded, as the benefit of this arrangement will be refunded to customers in rates.

NU Parent - Hedging: In March of 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 note that matures on April 1, 2012. Under fair value hedge accounting, the changes in fair value of the swap and the hedged long-term debt instrument are recorded in interest expense. The cumulative changes in the fair value of the swap and the long-term debt are recorded as derivative liabilities and decreases to long-term debt of $10.6 million at June 30, 2007 and $6.5 million at December 31, 2006.

5.

GOODWILL (Yankee Gas)

SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill and intangible assets deemed to have indefinite useful lives be reviewed for impairment at least annually by applying a fair value-based test. NU uses October 1st as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount.

The only NU reporting unit that currently maintains goodwill is the Yankee Gas reporting unit, which is classified under the regulated companies - gas reportable segment. The goodwill recorded related to the acquisition of Yankee

Gas is not being recovered from the customers of Yankee Gas. The goodwill balance was $287.6 million at both June 30, 2007 and December 31, 2006.

For information regarding NU's reportable segments, see Note 10, "Segment Information," to the condensed consolidated financial statements.

6.

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 independent power producer 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 30, 2007, CL&P filed its 2006 CTA and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements, with the DPUC. For the year ended December 31, 2006, total CTA cost of service exceeded CTA revenues by $5.6 million. This amount was recorded as a regulatory asset on the accompanying condensed consolidated balance sheets. In addition, CTA refunds for the period January 2006 through August 2006 totaled $99.8 million and resulted in an additional increase to CL&P s CTA regulatory asset. For the year ended December 31, 2006, the SBC cost of service exceeded SBC revenues by $24.3 million. Management expects a decision in this docket from the DPUC by the end of 2007 and does not expect the outcome to have a material adverse impact on CL&P's net income, financial position or cash flows.

Purchased Gas Adjustment: On September 9, 2005, the DPUC issued a draft decision regarding Yankee Gas Purchased Gas Adjustment (PGA) clause charges for the period of September 1, 2003 through August 31, 2004. The draft decision disallowed approximately $9 million in previously recovered PGA revenues associated with two separate Yankee Gas unbilled sales and revenue adjustments. At the request of Yankee Gas, the DPUC reopened the PGA hearings on September 20, 2005 and requested that Yankee Gas file supplemental information regarding the two adjustments. Yankee Gas complied with this request. The DPUC issued a new decision on April 20, 2006 requiring an audit of Yankee Gas' previously recovered PGA costs and deferred any conclusion on the $9 million of previously recovered revenues until the completion of the audit. In a subsequent draft decision regarding Yankee Gas PGA charges for the period September 1, 2004 through August 31, 2005, an additional $2 million related to previously recovered revenues was also identified, bringing the total maximum amount at issue with regard to PGA clause charges under audit to approximately $11 million.

The DPUC hired a consulting firm which has concluded an audit of Yankee Gas' previously recovered PGA costs and has submitted its final report. Management believes the unbilled sales and revenue adjustments and resulting charges to customers through the PGA clause for both periods were appropriate. Based on the facts of the case, the supplemental information provided to the DPUC and the consultant s final report, management believes the appropriateness of the PGA charges to customers for the time period under review will be approved, and has not reserved for any loss.

New Hampshire:

SCRC/ES Reconciliation and Rates: On an annual basis, PSNH files with the New Hampshire Public Utilities Commission (NHPUC) a stranded cost recovery charge/energy service (SCRC/ES) reconciliation filing for the preceding calendar year. The NHPUC reviews the filing, including a prudence review of the operations within PSNH's generation segment. On May 1, 2007, PSNH filed its 2006 SCRC/ES reconciliation with the NHPUC which is expected to be adjudicated in the third quarter of 2007. Management does 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.

On June 29, 2007, PSNH received approval from the NHPUC to lower the ES charge from $0.0859 per kilowatt-hour (KWH) to $0.0783 per KWH effective on July 1, 2007 with a partially offsetting increase to the SCRC charge from $0.0130 per KWH to $0.0143 per KWH. The rate changes will substantially lower the possibility of any material over/underrecoveries at December 31, 2007.

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 has opened a proceeding for these filings and is currently in the discovery phase. Evidentiary hearings are scheduled for late August of 2007. As the DPU has not yet issued a briefing schedule, the timing of the decision is uncertain. Management does not expect the outcome of the DPU's review of these filings to have a material adverse impact on WMECO's net income, financial position or cash flows.

B.

NRG Energy, Inc. Exposures (CL&P, Yankee Gas)

Certain subsidiaries of NU, including CL&P and Yankee Gas, entered into transactions with NRG Energy, Inc. (NRG) and certain of its subsidiaries. On May 14, 2003, NRG and certain subsidiaries of NRG filed voluntary bankruptcy petitions, and on December 5, 2003, NRG emerged from bankruptcy. NU's NRG-related exposures as a result of these transactions relate to 1) the refunding of approximately $28 million of congestion charges previously withheld from NRG prior to the implementation of standard market design (SMD) on March 1, 2003, 2) the recovery of approximately $28 million of CL&P's station service billings from NRG, which is currently the subject of an arbitration, and 3) the recovery of, among other claimed damages, 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.

On July 20, 2007, the United States District Court for the District of Connecticut issued a ruling granting CL&P's motion for summary judgment against NRG in the pre-SMD congestion litigation. In this decision, the court concluded that NRG was contractually obligated to pay for congestion charges imposed during the term of the October 29, 1999 standard offer service wholesale sales agreement between CL&P and NRG and found in favor of CL&P and against NRG on each of NRG's four counterclaims. NRG has 30 days from the entry of judgment to file an appeal.

While it is unable to determine the ultimate outcome of these issues, management does not expect their resolution will have a material adverse effect on NU's consolidated earnings or financial position.

C.

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

CL&P: These amounts represent commitments for various services and materials associated with the Middletown to Norwalk, Glenbrook Cables and the Norwalk to Northport-Long Island, New York transmission projects and other projects as of June 30, 2007:

(Millions of Dollars)	2007	2008	2009	2010	2011	Thereafter	Total
Transmission segment project commitments	$ 373.5	$ 342.0	$ 10.6	$ -	$ -	$ -	$ 726.1

PSNH: PSNH has entered into various arrangements for the purchase of coal and transportation services for fuel supply to its electric generating assets for 2007 through 2011. The purchase commitments at June 30, 2007 are as follows:

(Millions of Dollars)	2007	2008	2009	2010	2011	Thereafter	Total
Coal contracts	$ 49.0	$ 75.2	$ 27.0	$ 27.8	$ 28.3	$ -	$ 207.3

Select Energy: 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. These purchase commitments at June 30, 2007 are as follows:

(Millions of Dollars)	2007	2008	2009	2010	2011	Thereafter	Total
Select Energy purchase commitments	$ 216.5	$ 193.3	$ 29.7	$ 32.1	$ 31.2	$ 41.0	$ 543.8

Select Energy's purchase commitment amounts exceed the amount expected to be reported in fuel, purchased and net interchange power because many wholesale sales transactions are also classified in fuel, purchased and net interchange power, and certain purchases are included in revenues. Select Energy also maintains certain energy commitments whose 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.

The amounts and timing of the costs associated with Select Energy's purchase agreements will be impacted by the exit from the NU Enterprises' businesses.

D.

Environmental Matters (HWP)

The company remains in the process of evaluating additional potential remediation requirements at a river site in Massachusetts containing tar deposits. HWP is at least partially responsible for this site, and substantial remediation activities at this site have already been conducted. HWP first established a reserve for this site in 1994. Since that time, HWP has expensed approximately $13 million, of which $12.2 million has been spent and $0.8 million remains in the reserve. HWP's reserve is based on its most recent site assessment and estimate of required remediation costs. The ultimate remediation requirements will depend, among other things, on the level and extent of the remaining tar required to be removed, and the extent of HWP s responsibility. These matters are the subject of ongoing discussions with the Massachusetts Department of Environmental Protection and may change from time-to-time. HWP's share of the remediation costs related to this site is not recoverable from ratepayers. At this time, management cannot predict the outcome of this matter or its ultimate effect on NU. Any additional increase to the environmental remediation reserve for this site would be recorded in earnings in future periods when it is estimable and probable, and potential increases may be material. There were no changes to the environmental reserve in the second quarter of 2007.

E.

Consolidated Edison, Inc. Merger Litigation (NU)

Certain gain and loss contingencies exist with regard to the merger agreement between NU and Consolidated Edison, Inc. (Con Edison) and the related litigation.

In 2001, Con Edison advised NU that it was unwilling to close its merger with NU on the terms set forth in the parties' 1999 merger agreement (Merger Agreement). In March of 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

In a 2005 opinion, a panel of three judges at the Second Circuit held that the shareholders of NU had no right to sue Con Edison for its alleged breach of the parties' Merger Agreement. This ruling left intact the remaining claims between NU and Con Edison for breach of contract, which include NU's claim for recovery of costs and expenses of approximately $32 million and Con Edison's claim for damages of "at least $314 million." NU's request for a rehearing was denied in 2006. NU opted not to seek review of this ruling by the United States Supreme Court. In April of 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. NU's motion asserts that NU is entitled to a judgment in its favor with respect to this claim based on the undisputed material facts and applicable law. The matter is fully briefed and awaiting a decision. At this time, NU cannot predict the outcome of this matter or its ultimate effect on NU.

F.

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. In addition, NU has provided guarantees and various indemnifications on behalf of external parties as a result of the sales of SESI, the retail marketing business and the competitive generation business. The following table summarizes NU's maximum exposure at June 30, 2007, 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 estimated costs to complete or modify specific projects	Not Specified (1)	Through project completion	0.2
	Indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts	$2.5	2017-2018	0.1
	Surety bonds covering certain projects	$79.8	Through project completion	-

			(2)	
Hess (Retail Marketing Business)	General indemnifications in connection with the sale including compliance with laws, validity of contract information, completeness and accuracy of information provided, absence of default on contracts, and various claims	Not Specified (1)	None	-
ECP (Competitive Generation Business)	General indemnifications in connection with the sale of the generating assets of NGC and Mt. Tom including compliance with laws, validity of contract information, completeness and accuracy of information provided, absence of default on contracts, and various claims	Not Specified (1)	None	-
On behalf of subsidiaries:				
Regulated Companies	Surety bonds, primarily for self-insurance	$12.9	None	N/A
	Letters of credit	27.0	2007-2008	N/A
Rocky River Realty Company	Lease payments for real estate	11.3	2024	N/A
NUSCO	Lease payments for fleet of vehicles	10.0	None	N/A
SECI-CT and Boulos	Surety bonds covering ongoing projects	71.0	Through project completion	N/A
NGS	Insurance bonds and lease payment guarantees	1.2	None	N/A
Select Energy	Performance guarantees and surety bonds for retail marketing contracts	2.7 (3)	None (4)	N/A
	Performance guarantees for wholesale contracts	86.8 (3)	None	N/A

	Letters of credit	7.0	2007	N/A
HWP	Performance and payment guarantee related to coal purchase contract	Not Specified (5)	2009	N/A

(1)

There is no specified maximum exposure included in the related sale agreements. For retail marketing business guarantees, Hess may not assert an indemnification claim based on unintentional data errors unless and until damages exceed a $5 million aggregate threshold, at which point Hess may assert a claim for all damages; all other claims are subject to a $0.3 million threshold.

(2)

The company expects appropriate acknowledgment of project completion for the majority of these surety bonds by the end of 2007.

(3)

Maximum exposure is as of June 30, 2007; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited. The performance guarantees for the wholesale contracts expire in 2008.

(4)

NU is working with counterparties to terminate the remaining guarantees and does not currently anticipate that these remaining guarantees on behalf of Select Energy will result in significant guarantees of the performance of Hess.

(5)

There is no specified maximum exposure included in this guarantee agreement. NU has guaranteed the performance of HWP under a back-to-back agreement with ECP relating to an HWP coal supply contract. The maximum exposure to loss under very unlikely circumstances is estimated at approximately $55.9 million. NU would have recourse to ECP for approximately $40 million, of which $2 million is secured by an LOC.

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

In July of 2006, under its former SESI guarantee, NU was required to purchase contract payments relating to the only guaranteed SESI project that was behind schedule. In the second quarter of 2007, NU recorded a $0.5 million loss to reduce the carrying value of the contract payments purchased to the amount expected to be received from refinancing through SESI's completion of the project. The carrying value of these assets is $8.8 million at June 30, 2007 and is included in other deferred debits on the accompanying condensed consolidated balance sheets. NU may record additional losses associated with this transaction, the amount of which will depend on changes in interest rates used to determine SESI's refinancing proceeds, the amount of project cash available to offset NU's costs, and other factors.

G.

Transmission Rate Matters and FERC Regulatory Issues (CL&P, PSNH, WMECO)

Pursuant to an October 31, 2006 FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. NU and the other Regional Transmission Organization members are currently evaluating this FERC order. NU's transmission companies may be required to make additional refunds and currently estimates such pre-tax refunds to be potentially approximately $3.5 million (approximately $2 million after-tax). NU's distribution companies would receive a net after-tax benefit of approximately $0.4 million as a result of these refunds. The estimated refunds and benefits totaling approximately $1.6 million after-tax were not recorded at June 30, 2007.

7.

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

Total comprehensive income, which includes all comprehensive income/(loss) items by category, for the three and six months ended June 30, 2007 and 2006 is as follows:

	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:							
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
Total comprehensive income	$ 55.5	$ 24.4	$ 15.3	$ 4.6	$ 6.1	$ 0.3	$ 4.8

	Three Months Ended June 30, 2006						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income/(loss)	$ 22.2	$ 16.1	$ 14.9	$ 2.6	$ (14.3)	$ (0.1)	$ 3.0
Comprehensive (loss)/income items:							
Qualified cash flow hedging instruments	(6.9)	(2.7)	-	-	(4.2)	-	-
Unrealized gains/(losses) on securities	2.9	-	-	(0.1)	2.5	-	0.5
Net change in comprehensive (loss)/income items	(4.0)	(2.7)	-	(0.1)	(1.7)	-	0.5
Total comprehensive income/(loss)	$ 18.2	$ 13.4	$ 14.9	$ 2.5	$ (16.0)	$ (0.1)	$ 3.5

	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 (loss)/income items:							
Qualified cash flow hedging instruments	(1.6)	(1.6)	-	-	-	-	-
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

Six Months Ended June 30, 2006

(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income/(loss)	$ 12.1	$ 48.6	$ 20.0	$ 7.8	$ (76.9)	$ 11.7	$ 0.9
Comprehensive income/(loss) items:							
Qualified cash flow hedging instruments	13.2	(4.6)	-	-	17.9	-	(0.1)
Unrealized losses on securities	(0.2)	-	-	(0.1)	-	-	(0.1)
Other	2.4	-	-	-	-	-	2.4
Net change in comprehensive income/(loss) items	15.4	(4.6)	-	(0.1)	17.9	-	2.2
Total comprehensive income/(loss)	$ 27.5	$ 44.0	$ 20.0	$ 7.7	$ (59.0)	$ 11.7	$ 3.1

*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, 2007 and the twelve months ended December 31, 2006 are as follows:

(Millions of Dollars, Net of Tax)	Six Months Ended June 30, 2007	Twelve Months Ended December 31, 2006
Balance at beginning of period	$ 5.9	$ 18.2
Hedged transactions recognized into earnings	-	2.3
Amount reclassified into earnings due to discontinuation of cash flow hedges	-	(14.1)
Change in fair value of hedged transactions delivered	-	(4.5)
Cash flow transactions entered into for the period	(1.6)	4.0
Net change associated with the current period hedging transactions	(1.6)	(12.3)
Total fair value adjustments included in accumulated other comprehensive income	$ 4.3	$ 5.9

In the first quarter of 2006, $14.1 million was reclassified from accumulated other comprehensive income into earnings (included in other operation expenses) due to discontinuing cash flow hedge accounting and concluding that the retail marketing contracts hedged beyond June 1, 2006 were no longer probable of physical delivery due to the retail business being sold.

In March of 2006, CL&P entered into a forward lock agreement to hedge the interest rate associated with $125 million of its $250 million, 30-year fixed rate long-term debt issuance. Under the agreement, CL&P locked in a LIBOR swap rate of 5.322 percent based on the notional amount of $125 million in long-term debt that was issued in June of 2006. On June 1, 2006, the hedge was settled, and a charge of $4.6 million, net of tax ($7.8 million pre-tax), was recorded in accumulated other comprehensive income to be amortized into earnings over the term of the long-term debt.

In February of 2007, CL&P entered into two forward swap agreements to hedge the interest rates associated with $75 million of its $150 million, 10-year fixed rate long-term debt issuance and with $75 million of its $150 million, 30-year fixed rate long-term debt issuance. Under the agreements, CL&P locked in a LIBOR swap rate of 5.229 percent for the 10-year hedge and 5.369 percent for the 30-year hedge, both based on the notional amounts of $75 million in long-term debt that was issued in March of 2007. On March 27, 2007, the hedge was settled and a net-of-tax charge of $1.6 million, ($2.6 million pre-tax) was recorded in accumulated other comprehensive income to be amortized into earnings over the term of the long-term debt.

At June 30, 2007, it is estimated that a pre-tax $0.7 million included in the accumulated other comprehensive income balance will be reclassified as a decrease to earnings in the next year related to pension, supplemental executive retirement plan (SERP) and other postretirement benefits adjustments.

Accumulated other comprehensive income items unrelated to NU's cash flow hedging instruments totaled a positive $6.2 million and a negative $1.4 million at June 30, 2007 and December 31, 2006, respectively. These amounts relate to unrealized gains on investments in marketable debt and equity securities and the pension, SERP and other postretirement benefits adjustments, net of related income taxes.

8.

EARNINGS PER SHARE (NU)

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. The following table excludes 208,650 options and 218,650 options for the three and six months ended June 30, 2006, respectively, as these options were antidilutive. There were no antidilutive options for the three and six months ended June 30, 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,	
	2007	**2006**	**2007**	**2006**

(Millions of Dollars, Except for Share Information)				
Income/(loss) from continuing operations	$ 46.1	$ 14.3	$ 122.4	$ (6.4)
Income from discontinued operations	2.4	7.9	1.2	18.5
Net income	$ 48.5	$ 22.2	$ 123.6	$ 12.1
Basic EPS common shares outstanding (average)	154,729,676	153,628,709	154,539,678	153,535,675
Dilutive effect	483,418	293,926	562,994	273,458
Fully diluted EPS common shares outstanding (average)	155,213,094	153,922,635	155,102,672	153,809,133
Basic and Fully Diluted EPS:				
Income/(loss) from continuing operations	$ 0.30	$ 0.09	$ 0.79	$ (0.04)
Income from discontinued operations	0.01	0.05	0.01	0.12
Basic and fully diluted EPS	$ 0.31	$ 0.14	$ 0.80	$ 0.08

Restricted share units (RSUs) are included in basic common shares outstanding when shares are 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 difference between the market value of RSUs outstanding but not issued 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 difference between the intrinsic value of dilutive stock options outstanding and the total adoption compensation.

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

9.

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 (PBOP Plan). In addition, NU maintains a SERP which provides benefits to eligible participants, who are officers of NU that would have been provided to them under NU s Pension Plan if certain Internal Revenue Code and other limitations were not imposed.

NU estimated the December 31, 2006 prepaid or accrued pension asset or obligation based on an actuarial valuation as of the beginning of the year (January 1, 2006), adjusted for known changes during the year such as actual earnings, interest rate levels, expenses incurred and benefits paid during the year. The estimated December 31, 2006 balance was also used to estimate the related 2007 pension income or expense and the prepaid or accrued pension asset or obligation recorded through the first quarter of 2007. The December 31, 2006 year end estimates were adjusted and recorded in the second quarter of 2007 based on an actuarial valuation using actual data as of January 1, 2007. The actuarial valuation resulted in a $19.8 million increase to the net prepaid pension asset (see the table below for additional information regarding this adjustment).

On May 4, 2007, NU's Board of Trustees approved a COLA that increased retiree pension benefits for certain participants in the Pension Plan. The COLA was announced on May 8, 2007 at the annual meeting of NU's shareholders and resulted in a plan amendment and a remeasurement of the Pension Plan's benefit obligation on that date.

The COLA increased the Pension Plan's benefit obligation by $40 million, and was reflected as a prior service cost and as a decrease in the funded status of the Pension Plan. This amount will be amortized over a 12-year period representing average remaining service lives of employees. However, the $40 million increase in the Pension Plan's benefit obligation (decrease in the prepaid funded status) as a result of the COLA was more than offset by positive adjustments of approximately $100 million related to other aspects of the remeasurement, including favorable 2007 Pension Plan asset performance through May 8, 2007 and an increase in the discount rate from 5.9 percent at December 31, 2006 to 6.0 percent at the remeasurement date. On a combined basis, as a result of the May 8, 2007 remeasurement, the net prepaid pension asset increased by approximately $60 million.

These changes resulted in the following adjustments to amounts recognized for the Pension Plan in the accompanying condensed consolidated balance sheets at June 30, 2007:

(Millions of Dollars)	**Balances as of December 31, 2006**	**Expense for the Six Months Ended June 30, 2007**	**Change in Estimate**	**Adjustment for May 8, 2007 Plan Remeasurement**	**Balances as of June 30, 2007**
Regulatory assets	$ 223.5	$ (15.6)	$ (17.3)	$ (51.4)	$ 139.2
Prepaid pension	21.6	5.1	19.8	58.9	105.4

Total assets	$ 245.1	$ (10.5)	$ 2.5	$ 7.5	$ 244.6
Accumulated other comprehensive loss/(income), net of tax	$ 1.9	$ (0.2)	$ (1.5)	$ (4.3)	$ (4.1)

The impact of the change in estimate on the prepaid pension asset of $19.8 million for NU consolidated included increases to the prepaid pension assets of CL&P and WMECO in the amounts of $15.8 and $3 million, respectively. That impact also included a decrease to the accrued pension liability for PSNH of $2.5 million. These amounts were offset by a $1.5 million decrease to the net prepaid pension assets related to other NU subsidiaries. For CL&P, PSNH and WMECO, these changes decreased regulatory assets for deferred benefit costs in the same amounts, and had no impact on accumulated other comprehensive income.

The impact of the May 8, 2007 Pension Plan remeasurement on the prepaid pension asset of $58.9 million for NU consolidated included increases to the prepaid pension assets of CL&P and WMECO in the amounts of $25.8 and $5.7 million, respectively. That impact also included a decrease to the accrued pension liability for PSNH of $5.6 million. An additional net increase of $21.8 million to the net prepaid pension asset was recorded related to other NU subsidiaries. For CL&P, PSNH and WMECO, these changes decreased regulatory assets for deferred benefit costs in the same amounts, and had no impact on accumulated other comprehensive income.

The components of net periodic benefit expense/(income) for the Pension Plan, SERP, and PBOP Plan for the three and six months ended June 30, 2007 and 2006 are as follows:

NU	**For the Three Months Ended June 30,**					
	Pension Benefits		**Postretirement Benefits**		**SERP Benefits**	
(Millions of Dollars)	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**
Service cost	$ 12.5	$ 12.4	$ 2.1	$ 2.2	$ 0.2	**$** 0.3
Interest cost	35.5	31.2	6.6	6.9	0.5	0.5
Expected return on plan assets	(51.2)	(42.9)	(4.5)	(3.5)	-	-
Amortization of unrecognized net transition obligation	0.1	-	2.9	2.8	0.2	-
Amortization of prior service cost	2.3	1.4	(0.1)	(0.1)	-	-
Amortization of actuarial loss	5.0	9.0	2.9	4.5	-	0.2
Net periodic expense - before curtailments and termination benefits	4.2	11.1	9.9	12.8	0.9	1.0
Curtailments	-	(0.4)	-	-	-	-
Termination benefits	-	0.7	-	-	-	-
Total curtailments and termination benefits	-	0.3	-	-	-	-
Total - net periodic expense	$ 4.2	$ 11.4	$ 9.9	$ 12.8	$ 0.9	$ 1.0

NU	**For the Six Months Ended June 30,**					
	Pension Benefits		**Postretirement Benefits**		**SERP Benefits**	
(Millions of Dollars)	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**
Service cost	$ 24.3	$ 24.7	$ 4.2	$ 4.1	$ 0.4	**$** 0.5
Interest cost	69.1	63.4	13.3	13.7	1.0	1.0
Expected return on plan assets	(98.4)	(86.4)	(9.1)	(7.0)	-	-
Amortization of unrecognized net transition obligation/(asset)	0.1	(0.1)	5.8	5.6	-	-
Amortization of prior service cost	3.9	3.0	(0.1)	(0.1)	0.3	0.1
Amortization of actuarial loss	11.8	19.4	5.8	9.0	0.1	0.5

Net periodic expense - before curtailments and termination benefits		10.8		24.0		19.9		25.3		1.8		2.1
Curtailments		-		(0.4)		-		-		-		-
Termination benefits		-		0.7		-		-		-		-
Total curtailments and termination benefits		-		0.3		-		-		-		-
Total - net periodic expense	$	10.8	$	24.3	$	19.9	$	25.3	$	1.8	$	2.1

A portion of these pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were approximately $(0.2) million and $0.4 million for the three and six months ended June 30, 2007, respectively, and $2.6 million and $5.2 million for the three and six months ended June 30, 2006, respectively.

CL&P	**For the Three Months Ended June 30,**											
	Pension Benefits				**Postretirement Benefits**				**SERP Benefits**			
(Millions of Dollars)		**2007**		**2006**		**2007**		**2006**		**2007**		**2006**
Service cost	$	4.5	$	4.2	$	0.7	$	0.7	$	-	$	-
Interest cost		12.4		11.8		2.6		2.8		0.1		0.1
Expected return on plan assets		(23.6)		(20.3)		(1.8)		(1.4)		-		-
Amortization of unrecognized net transition obligation		-		-		1.6		1.5		-		-
Amortization of prior service cost		1.0		0.6		-		-		-		-
Amortization of actuarial loss		1.4		3.8		1.1		1.8		-		-
Net periodic expense - before curtailments and termination benefits		(4.3)		0.1		4.2		5.4		0.1		0.1
Curtailments		-		(0.1)		-		-		-		-
Termination benefits		-		(0.4)		-		(0.1)		-		-
Total curtailments and termination benefits		-		(0.5)		-		(0.1)		-		-
Total - net periodic (income)/expense	$	(4.3)	$	(0.4)	$	4.2	$	5.3	$	0.1	$	0.1

CL&P	For the Six Months Ended June 30,					
	Pension Benefits		Postretirement Benefits		SERP Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Service cost	$ 8.4	$ 8.6	$ 1.4	$ 1.4	$ -	$ -
Interest cost	24.7	23.8	5.3	5.5	0.1	0.1
Expected return on plan assets	(45.7)	(40.6)	(3.6)	(2.8)	-	-
Amortization of unrecognized net transition obligation	-	-	3.1	3.0	-	-
Amortization of prior service cost	1.7	1.3	-	-	-	-
Amortization of actuarial loss	3.9	7.8	2.2	3.6	0.1	0.1
Net periodic expense - before curtailments and termination benefits	(7.0)	0.9	8.4	10.7	0.2	0.2
Curtailments	-	(0.1)	-	-	-	-
Termination benefits	-	(0.4)	-	(0.1)	-	-
Total curtailments and termination benefits	-	(0.5)	-	(0.1)	-	-
Total - net periodic (income)/expense	$ (7.0)	$ 0.4	$ 8.4	$ 10.6	$ 0.2	$ 0.2

Not included in the pension (income)/expense amounts above are intercompany expense allocations totaling $2.9 million and $6 million for the three and six months ended June 30, 2007, respectively, and $2.8 million and $6.1 million for the three and six months ended June 30, 2006, respectively. Intercompany allocations of postretirement benefits totaled $1.8 million and $3.6 million for the three and six months ended June 30, 2007, respectively, and $1.9 million and $3.9 million for the three and six months ended June 30, 2006, 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 $1.3 million and $1.9 million for the three and six months ended June 30, 2007, respectively, and $0.4 million and $1.4 million for the three and six months ended June 30, 2006, respectively. The amounts for the three and six months ended June 30, 2007 offset capital costs, as pension income was recorded for those periods.

PSNH	For the Three Months Ended June 30,

(Millions of Dollars)	Pension Benefits 2007	Pension Benefits 2006	Postretirement Benefits 2007	Postretirement Benefits 2006	SERP Benefits 2007	SERP Benefits 2006
Service cost	$ 2.4	$ 2.4	$ 0.5	$ 0.5	$ -	$ -
Interest cost	5.7	4.9	1.2	1.3	-	-
Expected return on plan assets	(4.7)	(4.1)	(0.8)	(0.7)	-	-
Amortization of unrecognized net transition obligation	0.1	0.1	0.6	0.6	-	-
Amortization of prior service cost	0.5	0.3	-	-	-	-
Amortization of actuarial loss	1.0	1.4	0.5	0.9	0.1	0.1
Net periodic expense - before termination benefits	5.0	5.0	2.0	2.6	0.1	0.1
Termination benefits	-	0.1	-	-	-	-
Total - net periodic expense	$ 5.0	$ 5.1	$ 2.0	$ 2.6	$ 0.1	$ 0.1

PSNH — **For the Six Months Ended June 30,**

(Millions of Dollars)	Pension Benefits 2007	Pension Benefits 2006	Postretirement Benefits 2007	Postretirement Benefits 2006	SERP Benefits 2007	SERP Benefits 2006
Service cost	$ 5.0	$ 4.7	$ 0.9	$ 0.9	$ -	$ -
Interest cost	11.0	10.0	2.5	2.5	0.1	-
Expected return on plan assets	(9.0)	(8.2)	(1.7)	(1.3)	-	-
Amortization of unrecognized net transition obligation	0.1	0.2	1.2	1.2	-	-
Amortization of prior service cost	0.8	0.6	-	-	-	-
Amortization of actuarial loss	2.2	2.9	1.1	1.7	0.1	0.1
Net periodic expense - before termination benefits	10.1	10.2	4.0	5.0	0.2	0.1
Termination benefits	-	0.1	-	-	-	-
Total - net periodic expense	$ 10.1	$ 10.3	$ 4.0	$ 5.0	$ 0.2	$ 0.1

Not included in the pension expense amounts above are intercompany allocations totaling $0.5 million and $1 million for the three and six months ended June 30, 2007, respectively, and $0.4 million and $0.9 million for the three and six months ended June 30, 2006, respectively. Intercompany allocations of postretirement benefits totaled $0.3 million and $0.6 million for the three and six months ended June 30, 2007, respectively, and $0.3 million and $0.7 million for the three and six months ended June 30, 2006, 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 $2.5 million for the three and six months ended June 30, 2007, respectively, and $2 million and $3.4 million for the three and six months ended June 30, 2006, respectively.

WMECO	**For the Three Months Ended June 30,**				**For the Six Months Ended June 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
	2007	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**
(Millions of Dollars)								
Service cost	$ 1.0	$ 0.9	$ 0.2	$ 0.2	$ 1.7	$ 1.7	$ 0.3	$ 0.3
Interest cost	2.5	2.4	0.6	0.6	5.0	4.8	1.1	1.2
Expected return on plan assets	(5.2)	(4.5)	(0.5)	(0.4)	(10.1)	(8.9)	(0.9)	(0.7)
Amortization of unrecognized net transition obligation	-	-	0.3	0.3	-	-	0.7	0.6
Amortization of prior service cost	0.2	0.1	-	-	0.4	0.3	-	-
Amortization of actuarial loss	0.2	0.8	0.2	0.4	0.7	1.6	0.4	0.8
Net periodic expense/(income) - before termination benefits	(1.3)	(0.3)	0.8	1.1	(2.3)	(0.5)	1.6	2.2
Termination benefits	-	(0.1)	-	-	-	(0.1)	-	-
Total net periodic expense/(income)	$ (1.3)	$ (0.4)	$ 0.8	$ 1.1	$ (2.3)	$ (0.6)	$ 1.6	$ 2.2

A de minimis amount of SERP expense was recorded for WMECO for the three and six months ended June 30, 2007 and 2006.

Not included in the pension income amounts above are intercompany expense allocations totaling $0.5 million and $1 million for the three and six months ended June 30, 2007, respectively, and $0.5 million and $1.0 million for the three and six months ended June 30, 2006, respectively. Intercompany allocations of postretirement benefits totaled $0.3 million and $0.6 million for the three and six months ended June 30, 2007, respectively, and $0.3 million and $0.6 million for the three and six months ended June 30, 2006, 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 $0.8 million for the three and six months ended June 30, 2007, respectively, and $0.1 million for both the three and six months ended June 30, 2006. The capitalized amounts for 2007 and 2006 offset capital project costs, as pension income was recorded for those periods.

NU contributed $13 million in the second quarter of 2007 and $19.5 million in the first half of 2007 to fund its PBOP Plan. NU funded an additional $2.5 million to its PBOP Plan with funds received from the federal Medicare subsidy for a portion of its 2006 subsidy.

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 operates. Cash flows for total investments in plant included in the segment information below are cash capital expenditures that do not include 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), represents approximately 95 percent and 96 percent of NU's total revenues for the three and six months ended June 30, 2007. Similar amounts for 2006 were 86 percent and 80 percent, respectively. CL&P's, PSNH's and WMECO's complete condensed consolidated financial statements are included in this combined report on Form 10-Q. PSNH's distribution segment includes generation activities. Also included in this combined report on Form 10-Q is detailed information regarding CL&P's, PSNH's, and WMECO's transmission segments. Regulated companies revenues from the sale of electricity and natural gas primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer.

At June 30, 2007, the NU Enterprises business segment includes: 1) Select Energy (wholesale contracts), 2) NGS, 3) Woods Electrical - Other, 4) Boulos, 5) SECI-CT, and 6) NU Enterprises parent.

Other in the segment tables primarily consists of 1) the results of NU parent, which includes other income related to the equity in earnings of NU parent's subsidiaries and interest income from the NU Money Pool, which are both eliminated in consolidation, and interest income and expense related to the cash and debt of NU parent, respectively, 2) the revenues and expenses of NU's service companies, most of which are eliminated in consolidation, and 3) the results of other subsidiaries, which are comprised of the Rocky River Realty Company and the Quinnehtuk Company (real estate subsidiaries), Mode 1 Communications, Inc. and the results of the non-energy-related subsidiaries of Yankee Energy System, Inc. (Yankee Energy Services Company, Yankee Energy Financial Services Company, and NorConn Properties, Inc.).

As a result of the sale of NU Enterprises' retail marketing and competitive generation businesses, the financial information used by management was reduced to the remaining wholesale contracts, the operations of the remaining energy services businesses and NU Enterprises' parent company. As a result of exiting these businesses in 2006, the operations of NU Enterprises have been aggregated and presented as one reportable segment for the three and six months ended June 30, 2007 and 2006.

Effective on 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 the three and six months ended June 30, 2007.

Customer Concentrations: Select Energy provided basic generation service in the New Jersey market in 2007. In 2006 it provided service to the Maryland market as well. Select Energy revenues related to these contracts represented $48.1 million and $117.9 million for the three months ended June 30, 2007 and 2006, respectively, and $108.1 million and $250.5 million for the six months ended June 30, 2007 and 2006, respectively, of total NU Enterprises' billings. No other individual customer represented in excess of 10 percent of NU Enterprises' billings for the three and six months ended June 30, 2007 and 2006.

Select Energy reported the settlement of all derivative contracts of the wholesale business, including full requirements sales contracts and intercompany revenues, in fuel, purchased and net interchange power. This presentation is a result of applying mark-to-market accounting to those contracts due to the decision to exit the wholesale marketing business.

NU's segment information for the three and six months ended June 30, 2007 and 2006 is as follows (some amounts between the financial statements and between segment schedules may not agree due to rounding):

For the Three Months Ended June 30, 2007

Regulated Companies

(Millions of Dollars)	Distribution (1) Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,160.0	$ 95.0	$ 73.0	$ 72.5	$ 99.9	$ (108.3)	$ 1,392.1
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)	(70.4)	(93.7)	106.6	(1,167.8)
Operating income/(loss)	71.1	4.0	36.7	2.0	4.5	(1.0)	117.3
Interest expense, net of AFUDC	(41.4)	(4.2)	(8.3)	(2.2)	(8.9)	5.5	(59.5)
Interest income	1.0	-	0.7	0.7	7.6	(5.4)	4.6
Other income/(loss), net	3.8	0.5	2.6	-	29.5	(29.2)	7.2
Income tax expense	(10.5)	-	(10.1)	(0.4)	(0.5)	(0.6)	(22.1)
Preferred dividends	(0.9)	-	(0.5)	-	-	-	(1.4)
Income/(loss) from continuing operations	23.1	0.3	21.1	0.1	32.2	(30.7)	46.1
Income from discontinued operations	-	-	-	2.4	-	-	2.4
Net income/(loss)	$ 23.1	$ 0.3	$ 21.1	$ 2.5	$ 32.2	$ (30.7)	$ 48.5

(Millions of Dollars)	Regulated Companies: Distribution (1): Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
	For the Six Months Ended June 30, 2007						
Operating revenues	$ 2,541.4	$ 279.8	$ 141.8	$ 153.1	$ 193.9	$ (213.7)	$ 3,096.3
Depreciation and amortization	(196.1)	(11.6)	(18.2)	(0.3)	(4.1)	1.7	(228.6)
Restructuring and impairment charges	-	-	-	(0.2)	-	-	(0.2)
Other operating expenses	(2,187.2)	(239.6)	(55.4)	(140.7)	(181.7)	209.8	(2,594.8)
Operating income/(loss)	158.1	28.6	68.2	11.9	8.1	(2.2)	272.7
Interest expense, net of AFUDC	(83.8)	(8.5)	(17.1)	(5.2)	(17.1)	12.9	(118.8)
Interest income	2.0	-	1.1	1.3	20.3	(12.8)	11.9
Other income/(loss), net	8.0	1.0	3.9	-	86.0	(84.8)	14.1
Income tax expense	(24.6)	(7.2)	(18.3)	(1.8)	(1.7)	(1.1)	(54.7)
Preferred dividends	(2.0)	-	(0.8)	-	-	-	(2.8)
Income/(loss) 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/(loss)	$ 57.7	$ 13.9	$ 37.0	$ 7.4	$ 95.6	$ (88.0)	$ 123.6
Total assets (2)	$ 9,440.9	$ 1,230.3	$ -	$ 189.7	$ 4,428.8	$ (4,163.9)	$ 11,125.8
Cash flows for total	$ 184.4	$ 29.2	$ 270.2	$ 1.2	$ 6.1	$ -	$ 491.1

investments in plant

	For the Three Months Ended June 30, 2006						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,284.6	$ 88.4	$ 48.7	$ 246.6	$ 84.1	$ (91.3)	$ 1,661.1
Depreciation and amortization	(88.4)	(5.6)	(7.3)	(0.1)	(4.6)	3.4	(102.6)
Restructuring and impairment charges	-	-	-	(3.3)	-	-	(3.3)
Other operating expenses	(1,117.5)	(79.5)	(20.5)	(273.8)	(79.0)	88.4	(1,481.9)
Operating income/(loss)	78.7	3.3	20.9	(30.6)	0.5	0.5	73.3
Interest expense, net of AFUDC	(41.1)	(4.0)	(5.1)	(8.7)	(9.9)	7.9	(60.9)
Interest income	1.9	-	0.1	1.5	7.3	(8.2)	2.6
Other income/(loss), net	4.2	0.3	1.0	-	27.4	(23.3)	9.6
Income tax (expense)/benefit	(21.7)	0.3	(3.9)	15.6	1.9	(1.1)	(8.9)
Preferred dividends	(1.1)	-	(0.3)	-	-	-	(1.4)
Income/(loss) from continuing operations	20.9	(0.1)	12.7	(22.2)	27.2	(24.2)	14.3
Income from discontinued operations	-	-	-	7.9	-	-	7.9
Net income/(loss)	$ 20.9	$ (0.1)	$ 12.7	$ (14.3)	$ 27.2	$ (24.2)	$ 22.2

	For the Six Months Ended June 30, 2006						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 2,685.3	$ 272.5	$ 97.1	$ 773.6	$ 171.7	$ (191.8)	$ 3,808.4
Depreciation and amortization	(240.2)	(11.3)	(14.4)	(0.4)	(9.2)	6.9	(268.6)

Restructuring and impairment charges	-	-	-	(8.4)	-	-	(8.4)
Other operating expenses	(2,292.1)	(235.9)	(43.2)	(902.1)	(161.7)	184.6	(3,450.4)
Operating income/(loss)	153.0	25.3	39.5	(137.3)	0.8	(0.3)	81.0
Interest expense, net of AFUDC	(81.0)	(8.5)	(9.4)	(17.4)	(18.8)	14.8	(120.3)
Interest income	5.4	-	0.2	3.9	14.5	(15.3)	8.7
Other income/(loss), net	10.1	0.4	2.9	(0.5)	87.9	(83.2)	17.6
Income tax (expense)/benefit	(34.3)	(5.5)	(7.2)	55.9	1.6	(1.1)	9.4
Preferred dividends	(2.2)	-	(0.6)	-	-	-	(2.8)
Income/(loss) from continuing operations	51.0	11.7	25.4	(95.4)	86.0	(85.1)	(6.4)
Income from discontinued operations	-	-	-	18.5	-	-	18.5
Net income/(loss)	$ 51.0	$ 11.7	$ 25.4	$ (76.9)	$ 86.0	$ (85.1)	$ 12.1
Cash flows for total investments in plant	$ 148.7	$ 34.4	$ 172.5	$ 10.1	$ 15.0	$ -	$ 380.7

(1)

Includes PSNH's generation activities.

(2)

Information for segmenting total assets between electric distribution and transmission is not available at June 30, 2007. For NU and subsidiaries, distribution and transmission assets are disclosed in the electric distribution column 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, 2007 and 2006 is as follows:

	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	$ 112.6	$ 240.6	$ 353.2

in plant

	CL&P - For the Three Months Ended June 30, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 905.6	$ 34.1	$ 939.7
Depreciation and amortization	(57.8)	(5.5)	(63.3)
Other operating expenses	(814.8)	(13.7)	(828.5)
Operating income	33.0	14.9	47.9
Interest expense, net of AFUDC	(26.1)	(3.7)	(29.8)
Interest income	1.1	-	1.1
Other income, net	3.8	0.8	4.6
Income tax expense	(4.3)	(2.0)	(6.3)
Preferred dividends	(1.1)	(0.3)	(1.4)
Net income	$ 6.4	$ 9.7	$ 16.1

	CL&P - For the Six Months Ended June 30, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 1,877.6	$ 66.9	$ 1,944.5
Depreciation and amortization	(120.0)	(10.5)	(130.5)
Other operating expenses	(1,676.1)	(29.2)	(1,705.3)
Operating income	81.5	27.2	108.7
Interest expense, net of AFUDC	(50.9)	(7.0)	(57.9)
Interest income	4.3	0.1	4.4
Other income, net	8.1	2.6	10.7
Income tax expense	(11.0)	(3.5)	(14.5)
Preferred dividends	(2.2)	(0.6)	(2.8)
Net income	$ 29.8	$ 18.8	$ 48.6
Cash flows for total investments in plant	$ 85.1	$ 154.9	$ 240.0

	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

	PSNH - For the Three Months Ended June 30, 2006		
(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	$ 284.6	$ 10.0	$ 294.6
Depreciation and amortization	(27.1)	(1.3)	(28.4)
Other operating expenses	(220.1)	(4.8)	(224.9)
Operating income	37.4	3.9	41.3
Interest expense, net of AFUDC	(10.7)	(0.8)	(11.5)
Interest income	0.5	-	0.5
Other income, net	0.8	0.1	0.9

Income tax expense		(15.1)		(1.2)		(16.3)
Net income	$	12.9	$	2.0	$	14.9

	PSNH - For the Six Months Ended June 30, 2006					
(Millions of Dollars)	**Distribution (1)**		**Transmission**		**Total**	
Operating revenues	$	589.3	$	20.7	$	610.0
Depreciation and amortization		(112.3)		(2.6)		(114.9)
Other operating expenses		(424.2)		(9.6)		(433.8)
Operating income		52.8		8.5		61.3
Interest expense, net of AFUDC		(21.4)		(1.6)		(23.0)
Interest income		0.7		-		0.7
Other income, net		1.7		0.3		2.0
Income tax expense		(18.4)		(2.6)		(21.0)
Net income	$	15.4	$	4.6	$	20.0
Cash flows for total investments in plant	$	49.0	$	11.4	$	60.4

(1)

Includes PSNH's generation activities.

	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

	WMECO - For the Three Months Ended June 30, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 94.4	$ 4.6	$ 99.0
Depreciation and amortization	(3.3)	(0.6)	(3.9)
Other operating expenses	(82.7)	(2.0)	(84.7)
Operating income	8.4	2.0	10.4
Interest expense, net of AFUDC	(4.4)	(0.4)	(4.8)
Interest income	0.2	-	0.2

Other loss, net	(0.3)	-	(0.3)
Income tax expense	(2.3)	(0.6)	(2.9)
Net income	$ 1.6	$ 1.0	$ 2.6

	WMECO - For the Six Months Ended June 30, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 218.5	$ 9.6	$ 228.1
Depreciation and amortization	(7.9)	(1.2)	(9.1)
Other operating expenses	(192.0)	(4.5)	(196.5)
Operating income	18.6	3.9	22.5
Interest expense, net of AFUDC	(8.6)	(0.9)	(9.5)
Interest income	0.4	-	0.4
Other income, net	0.3	0.1	0.4
Income tax expense	(4.9)	(1.1)	(6.0)
Net income	$ 5.8	$ 2.0	$ 7.8
Cash flows for total investments in plant	$ 14.6	$ 6.2	$ 20.8

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, 2007, and the related condensed consolidated statements of income for the three-month and six-month periods ended June 30, 2007 and 2006, and of cash flows for the six-month periods ended June 30, 2007 and 2006. 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 Note 3, the Company recorded approximately $53 million, pre-tax charge in the six-month period ended June 30, 2006 to reduce the retail business to its fair value less cost to sell. Also, as discussed in Note 1.E., the Company adopted 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 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, 2006, 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 26, 2007 (which report included an explanatory paragraph related to recording charges, gains and losses in connection with the Company s ongoing divestiture activities, realizing a reduction to income tax expense related to a ruling that certain income taxes could not be used to reduce customer s rates, and the adoption of Statement of Financial Accounting Standard No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*), 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, 2006 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, 2007

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2007	December 31, 2006
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 2,006	$ 3,310
Investments in securitizable assets	343,891	375,656
Receivables, less provision for uncollectible accounts of $1,979 in 2007 and $1,679 in 2006	85,368	73,052
Accounts receivable from affiliated companies	816	1,965
Unbilled revenues	7,949	8,044
Materials and supplies	47,443	39,447
Derivative assets - current	50,830	45,031
Prepayments and other	10,766	15,945
	549,069	562,450
Property, Plant and Equipment:		
Electric utility	4,619,050	4,557,231
Less: Accumulated depreciation	1,255,512	1,260,526
	3,363,538	3,296,705
Construction work in progress	588,098	337,665
	3,951,636	3,634,370
Deferred Debits and Other Assets:		
Regulatory assets	1,334,878	1,477,375
Prepaid pension	297,343	243,139

Derivative assets - long-term		274,345		249,423
Other		141,636		154,537
		2,048,202		2,124,474
Total Assets	$	6,548,907	$	6,321,294

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, 2007	December 31, 2006
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to affiliated companies	$ 156,725	$ 258,925
Accounts payable	323,220	326,163
Accounts payable to affiliated companies	41,067	47,906
Accrued taxes	50,285	186,647
Accrued interest	38,633	29,587
Derivative liabilities - current	3,672	4,101
Other	79,271	80,543
	692,873	933,872
Rate Reduction Bonds	666,103	743,899
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	678,719	719,470
Accumulated deferred investment tax credits	22,716	24,019
Deferred contractual obligations	169,433	185,195
Regulatory liabilities	640,203	582,841
Derivative liabilities - long-term	27,091	31,923
Accrued postretirement benefits	79,504	85,768
Other	165,048	127,638
	1,782,714	1,756,854
Capitalization:		
Long-Term Debt	1,823,450	1,519,440

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 2007 and 2006		60,352	60,352
Capital surplus, paid in		888,042	672,693
Retained earnings		516,117	513,344
Accumulated other comprehensive income		3,056	4,640
Common Stockholder's Equity		1,467,567	1,251,029
Total Capitalization		3,407,217	2,886,669
Commitments and Contingencies (Note 6)			
.			
Total Liabilities and Capitalization	$	6,548,907	$ 6,321,294

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,	
	2007	2006	2007	2006
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 870,379	$ 939,720	$ 1,914,065	$ 1,944,480
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	516,270	601,737	1,205,043	1,266,664
Other	143,664	170,114	277,238	314,378
Maintenance	29,456	23,105	50,890	43,557
Depreciation	38,293	36,691	76,482	72,434
Amortization of regulatory assets/(liabilities), net	9,649	(2,427)	9,319	(4,321)
Amortization of rate reduction bonds	31,268	29,070	66,929	62,523
Taxes other than income taxes	37,828	33,492	85,249	80,538
Total operating expenses	806,428	891,782	1,771,150	1,835,773
Operating Income	63,951	47,938	142,915	108,707
Interest Expense:				
Interest on long-term debt	21,564	14,874	39,180	28,947
Interest on rate reduction bonds	9,747	11,982	19,867	24,566
Other interest	1,630	2,979	8,952	4,424

Interest expense, net	32,941	29,835	67,999	57,937
Other Income, Net	6,879	5,707	12,730	14,996
Income Before Income Tax Expense	37,889	23,810	87,646	65,766
Income Tax Expense	12,103	6,338	26,866	14,464
Net Income	$ 25,786	$ 17,472	$ 60,780	$ 51,302

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,	
	2007	2006
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 60,780	$ 51,302
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	9,699	8,629
Depreciation	76,482	72,434
Deferred income taxes	(13,111)	56,230
Amortization of regulatory assets/(liabilities), net	9,319	(4,321)
Amortization of rate reduction bonds	66,929	62,523
Amortization/(deferral) of recoverable energy costs	2,064	(30,858)
Pension (income)/expense, net of capitalized portion	(4,097)	467
Regulatory overrecoveries/(refunds)	41,371	(111,842)
Deferred contractual obligations	(15,762)	(33,475)
Other non-cash adjustments	(7,442)	(21,367)
Other sources of cash	-	19,008
Other uses of cash	(11,915)	(3,893)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(8,708)	16,915
Materials and supplies	(7,996)	(4,586)
Investments in securitizable assets	17,675	(19,330)
Other current assets	4,440	4,950
Accounts payable	(18,242)	63,543
Taxes receivable and accrued taxes	(150,041)	(41,462)

Other current liabilities		6,938		(2,051)
Net cash flows provided by operating activities		58,383		82,816
Investing Activities:				
Investments in plant		(353,241)		(240,040)
Proceeds from sales of investment securities		858		770
Purchases of investment securities		(896)		(796)
Rate reduction bond escrow		5,027		1,877
Other investing activities		749		(2,278)
Net cash flows used in investing activities		(347,503)		(240,467)
Financing Activities:				
Issuance of long-term debt		300,000		250,000
Retirement of rate reduction bonds		(77,796)		(73,217)
Decrease in NU Money Pool borrowing		(102,200)		(26,700)
Capital contributions from Northeast Utilities Parent		215,000		60,000
Cash dividends on preferred stock		(2,779)		(2,779)
Cash dividends on common stock		(39,591)		(31,865)
Other financing activities		(4,818)		(327)
Net cash flows provided by financing activities		287,816		175,112
Net (decrease)/increase in cash		(1,304)		17,461
Cash - beginning of period		3,310		2,301
Cash - end of period	$	2,006	$	19,762

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2007	December 31, 2006
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 83	$ 31
Receivables, less provision for uncollectible accounts of $2,706 in 2007 and $2,626 in 2006	77,627	86,784
Accounts receivable from affiliated companies	4,400	590
Unbilled revenues	44,061	44,433
Taxes receivable	24,419	6,671
Fuel, materials and supplies	76,964	84,856
Derivative assets - current	879	-
Prepayments and other	15,391	12,652
	243,824	236,017
Property, Plant and Equipment:		
Electric utility	1,960,030	1,893,124
Other	6,266	5,816
	1,966,296	1,898,940
Less: Accumulated depreciation	737,426	723,764
	1,228,870	1,175,176
Construction work in progress	65,064	67,202
	1,293,934	1,242,378
Deferred Debits and Other Assets:		
Regulatory assets	484,187	524,536
Other	74,577	68,345

		558,764	592,881
Total Assets	$	2,096,522	$ 2,071,276

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, 2007	December 31, 2006
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to affiliated companies	$ 73,200	$ 36,500
Accounts payable	70,899	69,948
Accounts payable to affiliated companies	17,087	22,327
Accrued interest	8,497	8,641
Derivative liabilities - current	15,846	39,180
Other	15,422	2,362
	200,951	178,958
Rate Reduction Bonds	308,304	333,831
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	191,490	200,136
Accumulated deferred investment tax credits	730	877
Deferred contractual obligations	32,160	35,623
Regulatory liabilities	119,220	115,731
Derivative liabilities - long-term	1,246	-
Accrued pension	149,534	150,634
Accrued postretirement benefits	33,813	36,521
Other	43,258	44,304
	571,451	583,826
Capitalization:		
Long-Term Debt	507,106	507,099
Common Stockholder's Equity:		

Common stock, $1 par value - authorized 100,000,000 shares; 301 shares outstanding in 2007 and 2006		-	-
Capital surplus, paid in		260,788	231,171
Retained earnings		247,667	236,215
Accumulated other comprehensive income		255	176
Common Stockholder's Equity		508,710	467,562
Total Capitalization		1,015,816	974,661
Commitments and Contingencies (Note 6)			
Total Liabilities and Capitalization	$	2,096,522	$ 2,071,276

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,	
	2007	2006	2007	2006
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 250,233	$ 294,638	$ 527,329	$ 609,954
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	126,187	147,964	268,612	290,202
Other	49,488	45,867	102,539	88,842
Maintenance	22,708	22,246	40,112	35,737
Depreciation	13,354	12,254	26,643	24,503
Amortization of regulatory (liabilities)/assets, net	(15,503)	4,144	(11,709)	66,220
Amortization of rate reduction bonds	12,697	11,975	25,603	24,166
Taxes other than income taxes	9,734	8,923	19,884	19,018
Total operating expenses	218,665	253,373	471,684	548,688
Operating Income	31,568	41,265	55,645	61,266
Interest Expense:				
Interest on long-term debt	6,254	5,959	12,405	11,683
Interest on rate reduction bonds	4,603	5,294	9,311	10,829
Other interest	787	215	1,380	445

Interest expense, net	11,644	11,468	23,096	22,957
Other Income	720	1,445	1,393	2,764
Income Before Income Tax Expense	20,644	31,242	33,942	41,073
Income Tax Expense	5,399	16,338	8,730	21,037
Net Income	$ 15,245	$ 14,904	$ 25,212	$ 20,036

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, 2007	Six Months Ended June 30, 2006
	(Thousands of Dollars)	
Operating activities:		
Net income	$ 25,212	$ 20,036
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	1,407	1,994
Depreciation	26,643	24,503
Deferred income taxes	58	(18,081)
Amortization of regulatory (liabilities)/assets, net	(11,709)	66,220
Amortization of rate reduction bonds	25,603	24,166
Pension expense, net of capitalized portion	7,718	6,883
Regulatory underrecoveries	(3,473)	(674)
Deferred contractual obligations	(3,463)	(7,594)
Other non-cash adjustments	(2,967)	(6,714)
Other uses of cash	(11,730)	(3,017)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	4,312	24,760
Taxes receivable	(13,583)	(20,044)
Fuel, materials and supplies	7,892	(4,670)
Other current assets	(5,739)	306
Accounts payable	2,105	8,673
Other current liabilities	4,291	(254)
Net cash flows provided by operating activities	52,577	116,493

Investing Activities:			
Investments in plant		(79,470)	(60,408)
Proceeds from sales of investment securities		1,471	1,321
Purchases of investment securities		(1,536)	(1,365)
Other investing activities		1,779	(1,756)
Net cash flows used in investing activities		(77,756)	(62,208)
Financing Activities:			
Retirement of rate reduction bonds		(25,527)	(24,072)
Increase/(decrease) in NU Money Pool borrowing		36,700	(4,600)
Capital contributions from Northeast Utilities Parent		29,500	2,500
Cash dividends on common stock		(15,359)	(29,247)
Other financing activities		(83)	1,187
Net cash flows provided by/(used in) financing activities		25,231	(54,232)
Net increase in cash		52	53
Cash - beginning of period		31	27
Cash - end of period	$	83	$ 80

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED
BALANCE SHEETS
(Unaudited)

	June 30, 2007	December 31, 2006
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 1,093	$ 1,336
Receivables, less provision for uncollectible accounts of $6,320 in 2007 and $5,073 in 2006	53,170	43,182
Accounts receivable from affiliated companies	5,191	5,628
Unbilled revenues	16,654	15,940
Taxes receivable	9,647	-
Materials and supplies	1,825	1,875
Marketable securities - current	24,827	28,054
Prepayments and other	2,022	1,080
	114,429	97,095
Property, Plant and Equipment:		
Electric utility	720,533	703,723
Less: Accumulated depreciation	204,923	201,099
	515,610	502,624
Construction work in progress	26,487	23,470
	542,097	526,094
Deferred Debits and Other Assets:		
Regulatory assets	214,641	252,346
Prepaid pension	82,026	69,933

Marketable securities - long-term		30,846	25,964
Other		14,425	17,261
		341,938	365,504
Total Assets	$	998,464	$ 988,693

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, 2007	December 31, 2006
	(Thousands of Dollars)	
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to affiliated companies	$ 67,800	$ 30,800
Accounts payable	25,162	28,008
Accounts payable to affiliated companies	5,905	4,184
Accrued taxes	336	27,615
Accrued interest	4,488	4,546
Other	10,842	9,273
	114,533	104,426
Rate Reduction Bonds	92,995	99,428
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	188,703	197,881
Accumulated deferred investment tax credits	2,167	2,319
Deferred contractual obligations	46,447	50,711
Regulatory liabilities	34,892	26,756
Accrued postretirement benefits	13,576	14,293
Other	12,692	12,136
	298,477	304,096
Capitalization:		
Long-Term Debt	263,139	261,777

Common Stockholder's Equity:				
Common stock, $25 par value - authorized				
1,072,471 shares; 434,653 shares outstanding				
in 2007 and 2006		10,866		10,866
Capital surplus, paid in		119,389		114,544
Retained earnings		98,218		92,663
Accumulated other comprehensive income		847		893
Common Stockholder's Equity		229,320		218,966
Total Capitalization		492,459		480,743
Commitments and Contingencies (Note 6)				
Total Liabilities and Capitalization	$	998,464	$	988,693

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,	
	2007	2006	2007	2006
	(Thousands of Dollars)			
Operating Revenues	$ 112,363	$ 99,037	$ 241,921	$ 228,077
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	56,736	61,418	127,907	150,293
Other	25,037	17,167	49,464	32,705
Maintenance	4,985	3,521	9,317	7,353
Depreciation	5,238	4,234	10,486	8,527
Amortization of regulatory assets/(liabilities), net	1,926	(3,271)	4,215	(5,457)
Amortization of rate reduction bonds	3,151	2,953	6,382	5,987
Taxes other than income taxes	2,976	2,646	6,401	6,124
Total operating expenses	100,049	88,668	214,172	205,532
Operating Income	12,314	10,369	27,749	22,545
Interest Expense:				
Interest on long-term debt	2,656	2,678	5,305	5,422
Interest on rate reduction bonds	1,490	1,707	3,011	3,469
Other interest	963	394	1,528	642
Interest expense, net	5,109	4,779	9,844	9,533
Other Income/(Loss)	448	(22)	936	758

Income Before Income Tax Expense	7,653	5,568	18,841	13,770
Income Tax Expense	3,063	2,939	7,334	5,964
Net Income	$ 4,590	$ 2,629	$ 11,507	$ 7,806

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,	
	2007	2006
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 11,507	$ 7,806
Adjustments to reconcile to net cash flows		
(used in)/provided by operating activities:		
Bad debt expense	3,282	2,779
Depreciation	10,486	8,527
Deferred income taxes	(8,590)	8,172
Amortization of regulatory assets/(liabilities), net	4,215	(5,457)
Amortization of rate reduction bonds	6,382	5,987
Pension income, net of capitalized portion	(1,500)	(343)
Regulatory overrecoveries/(underrecoveries)	24,642	(10,666)
Deferred contractual obligations	(4,264)	(9,215)
Other non-cash adjustments	(1,507)	(2,501)
Other sources of cash	370	3,293
Other uses of cash	(398)	-
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(13,083)	3,907
Materials and supplies	50	(328)
Other current assets	(942)	34
Accounts payable	(1,782)	(8,002)
Taxes receivable and accrued taxes	(34,746)	(2,642)
Other current liabilities	274	389
	(5,604)	1,740

Net cash flows (used in)/provided by operating activities			
Investing Activities:			
Investments in plant		(21,921)	(20,776)
Proceeds from sales of investment securities		76,427	55,799
Purchases of investment securities		(78,118)	(56,986)
Other investing activities		(5)	165
Net cash flows used in investing activities		(23,617)	(21,798)
Financing Activities:			
Retirement of rate reduction bonds		(6,433)	(6,038)
Increase in short-term debt		-	10,000
Increase in NU Money Pool borrowing		37,000	300
Capital contributions from Northeast Utilities Parent		4,800	20,500
Cash dividends on common stock		(6,389)	(3,973)
Net cash flows provided by financing activities		28,978	20,789
Net (decrease)/increase in cash		(243)	731
Cash - beginning of period		1,336	1
Cash - end of period	$	1,093	$ 732

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

This discussion should be read in conjunction with the condensed consolidated financial statements and footnotes in this Form 10-Q, the First Quarter 2007 Form 10-Q and the Northeast Utilities and subsidiaries combined 2006 Form 10-K as filed with the Securities and Exchange Commission (SEC) (NU 2006 Form 10-K). All per share amounts are reported on a fully diluted basis.

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:

- Northeast Utilities (NU or the company) earned $48.5 million, or $0.31 per share, in the second quarter of 2007, compared with earnings of $22.2 million, or $0.14 per share, in the second quarter of 2006. The results in 2007 included regulated company net income of $44.5 million, or $0.29 per share, after payment of preferred dividends, NU Enterprises, Inc. (NU Enterprises) net income of $2.5 million, or $0.01 per share, and parent and affiliates net income of $1.5 million, or $0.01 per share.

- NU earned $123.6 million, or $0.80 per share, in the first half of 2007, compared with earnings of $12.1 million, or $0.08 per share, in the first half of 2006. The results in 2007 included regulated company net income of $108.6 million, or $0.70 per share, after payment of preferred dividends, NU Enterprises net income of $7.4 million, or $0.05 per share, and parent and affiliates net income of $7.6 million, or $0.05 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 $23.4 million in the second quarter of 2007 and $71.6 million in the first half of 2007, compared with earnings of $20.8 million in the second quarter of 2006 and $62.7 million in the first half of 2006.

- The transmission segments of CL&P, PSNH and WMECO earned $21.1 million in the second quarter of 2007 and $37 million in the first half of 2007, compared with $12.7 million in the second quarter of 2006 and $25.4 million in the first half of 2006.

- NU Enterprises earned $2.5 million in the second quarter of 2007 and $7.4 million in the first half of 2007, compared with losses of $14.3 million in the second quarter of 2006 and $76.9 million in the first half of 2006. These amounts include negative mark-to-market impacts of $2.7 million for the second quarter of 2007 and $1.2 million for the first six months of 2007 from its remaining wholesale contracts, which have significantly decreased in number since 2006.

- NU continues to project consolidated 2007 earnings of between $1.30 per share and $1.55 per share. The company's earnings guidance does not include the impact of marking-to-market NU Enterprises' wholesale energy contracts.

- On May 7, 2007, the NU Board of Trustees approved a dividend of $0.20 per share, a 6.7 percent increase over the previous dividend rate, payable on September 28, 2007 to shareholders of record as of September 1, 2007. Management expects to continue its current policy of dividend increases, subject to the approval of the NU Board of Trustees and the company's future earnings and cash requirements.

Legislative, Regulatory and Other Items:

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On July 30, 2007, CL&P filed an application with the Connecticut Department of Public Utility Control (DPUC) to raise distribution rates by approximately $189 million effective on January 1, 2008 and approximately $22 million effective in January of 2009. CL&P expects the DPUC to hold hearings on the proposal in the late fall of 2007 and to issue a decision in early 2008.

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On June 29, 2007, the DPUC approved a rate case settlement agreement between Yankee Gas, the Connecticut Office of Consumer Counsel (OCC) and the DPUC's Prosecutorial Division that resulted in an annualized increase of $22.1 million or 4.2 percent in Yankee Gas' base rates effective on July 1, 2007. The settlement agreement provided for recovery of costs associated with Yankee Gas' liquefied natural gas (LNG) storage and production facility.

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On May 25, 2007, the New Hampshire Public Utilities Commission (NHPUC) approved a distribution and transmission rate case settlement agreement between PSNH, the NHPUC staff and the Office of Consumer Advocate (OCA). The permanent settlement agreement provided for a $37.7 million annualized increase beginning on July 1, 2007, along with the previous $24.5 million distribution rate settlement increase that was effective on July 1, 2006. The $37.7 million includes a one-year revenue increase of approximately $9 million related to additional revenues to recoup the difference between the interim and permanent rates for the period July 1, 2006 through June 30, 2007. Overall, PSNH's average retail rate decreased 0.4 percent on July 1, 2007 primarily due to a lower energy service rate.

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Pursuant to state law, CL&P and The United Illuminating Company (UI) have signed contracts for differences with three generators for 782 megawatts (MW) of capacity selected in a DPUC request for proposal (RFP) and for a 5 MW demand response project selected by the DPUC. The two utilities have filed a sharing agreement with the DPUC that provides for the costs and benefits of all contracts to be split 80 percent to CL&P and 20 percent to UI. Once these contracts are approved by the DPUC, the utilities are directed to negotiate cost-of-service based contracts with the generators for the energy associated with these projects. CL&P also signed a contract to purchase energy, capacity and renewable energy credits (RECs), subject to the 80/20 sharing agreement, from a biomass energy plant yet to be built. The utilities expect to enter into contracts for up to an additional 125 MW of renewable resource generation, once these projects are selected by the DPUC. CL&P s portion of the costs or benefits of these contracts will be paid by or refunded to CL&P s customers. For further information regarding this matter, see the Regulatory Developments and Rate Matters section of this management's discussion and analysis.

Liquidity:

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NU's liquidity position continues to benefit from the proceeds the company received from the sale of NU Enterprises' competitive generation business in November of 2006 and the issuance of $300 million of CL&P long-term debt. As expected, the company's level of consolidated cash on hand declined in the first half of 2007 primarily as a result of the payment of $398.5 million in federal and state income taxes related to the sale of the competitive generation business.

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NU's cash capital expenditures totaled $491.1 million in the first half of 2007, compared with $380.7 million in the first half of 2006. The increase was primarily the result of higher transmission capital expenditures, particularly at

CL&P.

- Negative consolidated operating cash flows were $37.5 million in the first half of 2007, primarily due to the $398.5 million of federal and state income tax payments made in the first quarter of 2007 mentioned above. Excluding the tax payments of $398.5 million and $55 million made in the first quarter of 2007 and 2006, respectively, NU's cash flows from operations in the first half of 2007 totaled $361 million, compared with $268.1 million in the first half of 2006. The improved 2007 cash flows excluding the tax payments were primarily due to a reduction in regulatory refunds as was expected, a reduction in payments made to the Connecticut Yankee Atomic Power Company (CYAPC), the Yankee Atomic Electric Company (YAEC) and the Maine Yankee Atomic Power Company (MYAPC) (collectively, the Yankee Companies) for decommissioning and closure costs, lower cash payments related to Select Energy's derivative contracts and changes in accounts receivable and payable due to the divestiture of the NU Enterprises' businesses in 2006.

- NU paid common dividends of $58.5 million in the first half of 2007, compared with $54 million in the first half of 2006.

Overview

Consolidated: NU earned $48.5 million, or $0.31 per share, in the second quarter of 2007, compared with earnings of $22.2 million, or $0.14 per share, in the second quarter of 2006. NU earned $123.6 million, or $0.80 per share, in the first half of 2007, compared with earnings of $12.1 million, or $0.08 per share, in the first half of 2006. A summary of NU's earnings/(losses) by segment, which may or may not reflect aggregations of specific subsidiaries, for the second quarter and first half of 2007 and 2006 is as follows:

	For the Three Months Ended June 30,				**For the Six Months Ended June 30,**			
	2007		**2006**		**2007**		**2006**	
(Millions of Dollars, except per share amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Regulated companies	$ 44.5	$ 0.29	$ 33.5	$ 0.22	$ 108.6	$ 0.70	$ 88.1	$ 0.58
NU Enterprises	2.5	0.01	(14.3)	(0.10)	7.4	0.05	(76.9)	(0.50)
Parent and affiliates	1.5	0.01	3.0	0.02	7.6	0.05	0.9	-
Net Income	$ 48.5	$ 0.31	$ 22.2	$ 0.14	$ 123.6	$ 0.80	$ 12.1	$ 0.08

The only common equity securities that are publicly traded are common shares of NU. The earnings per share (EPS) of each segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct interest in NU's assets and liabilities as a whole. EPS by segment is a non-GAAP measure. Management uses this measure to provide segmented earnings guidance and believes that this measurement is useful to investors to evaluate the actual financial performance and contribution of its business segments. These non-GAAP measures should not be considered as an alternative to NU consolidated EPS determined in accordance with GAAP as an indicator of operating performance.

Regulated Companies: NU's regulated companies, which are comprised of CL&P, PSNH, WMECO and Yankee Gas, segment their earnings between their electric transmission segments and their electric and gas distribution segments, with PSNH generation included with its distribution segment. A summary of regulated company earnings by segment for the second quarter and first half of 2007 and 2006 is as follows (millions of dollars):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
CL&P Transmission*	$ 17.4	$ 9.7	$ 30.4	$ 18.8
PSNH Transmission	2.6	2.0	4.5	4.6
WMECO Transmission	1.1	1.0	2.1	2.0
Total Transmission	21.1	12.7	37.0	25.4
CL&P Distribution*	7.0	6.4	27.6	29.8
PSNH Distribution and Generation	12.6	12.9	20.7	15.4
WMECO Distribution	3.5	1.6	9.4	5.8
Yankee Gas	0.3	(0.1)	13.9	11.7
Total Distribution and Generation	23.4	20.8	71.6	62.7
Net Income - Regulated Companies	$ 44.5	$ 33.5	$ 108.6	$ 88.1

*After preferred dividends in all periods.

The higher second quarter 2007 and first half 2007 transmission segment earnings reflect a higher level of investment in this segment as the company builds out its infrastructure to meet customer reliability needs. CL&P s transmission earnings increased primarily due to CL&P s significant ongoing investment in projects in southwest Connecticut.

CL&P's second quarter 2007 distribution segment earnings were slightly higher than the same period of 2006 due to a 2.2 percent increase in sales, a $7 million annualized distribution rate increase that took effect on January 1, 2007, and the absence of a Competitive Transition Assessment (CTA) -related rate base credit that was attributable to deferred tax liabilities on the generation assets sold by NGC on November 1, 2006, offset by higher operating, depreciation and interest expenses. In addition, earnings in the second quarter of 2006 included a fixed procurement fee of 0.50 mills per kilowatt-hour (KWH) of $1.6 million that CL&P was allowed to collect from customers who purchased transitional standard offer (TSO) service. The procurement fee expired at the end of 2006.

CL&P's distribution segment earnings for the first six months of 2007 were $2.2 million lower than the first half of 2006 due to higher operating, depreciation, and interest expenses, the absence of a state tax settlement that benefited CL&P by $4.9 million in the first quarter of 2006, and the absence of the fixed procurement fee of $3.3 million, partially offset by a 1.9 percent increase in sales, the $7 million annualized distribution rate increase, and the absence of a CTA-related rate base credit that was attributable to deferred tax liabilities on the generation assets sold. For the 12 months ended June 30, 2007, CL&P's Regulatory ROE was 7.8 percent. Management currently estimates that CL&P's Regulatory ROE will be between 7 percent and 7.5 percent through the end of 2007, substantially below its allowed 9.85 percent Regulatory ROE.

PSNH's second quarter 2007 distribution and generation segment earnings were slightly lower than the same period of 2006 due primarily to the timing of income tax recognition in 2006 that resulted in a second quarter 2006 benefit that was offset by higher income taxes in the third and fourth quarters of 2006. The absence of an income tax benefit in the second quarter of 2007 was mostly offset by a 0.5 percent increase in sales, a $24.5 million annualized interim rate increase that took effect on July 1, 2006, the implementation of a retail transmission cost tracking mechanism, and the recovery of approximately $4.5 million of retail transmission costs that were expensed in 2006.

PSNH's distribution and generation earnings for the six months ended June 30, 2007 were $5.3 million higher than the same period of 2006 due to a 1.6 percent increase in sales, the $24.5 million annualized interim rate increase, the implementation of a retail transmission cost tracking mechanism, and the recovery of approximately $4.5 million of retail transmission costs that were expensed in 2006, partially offset by increased operating and interest expenses and the absence of the income tax benefit recorded in the second quarter of 2006. For the 12 months ended June 30, 2007, PSNH's Regulatory ROE was 9.4 percent. Management expects that PSNH will be able to earn between a 9 percent and 10 percent Regulatory ROE in 2007 and 2008 as a result of the increased revenues generated by the rate settlement that took effect on July 1, 2007.

WMECO's second quarter and first half of 2007 distribution segment earnings were higher than the same periods of 2006 by $1.9 million and $3.6 million, respectively, due to increased sales and the impact of a distribution rate settlement that took effect on

January 1, 2007, which included an annualized distribution rate increase of $1 million and several cost tracking mechanisms, partially offset by higher operating, depreciation, and interest expenses. For the 12 months ended June 30, 2007, WMECO's Regulatory ROE was 10.1 percent. Management expects that WMECO will be able to earn between a 9 percent and 10 percent Regulatory ROE during 2007 and 2008.

Yankee Gas' second quarter and first half of 2007 earnings were higher than the same periods in 2006 primarily due to an 11 percent increase in firm natural gas sales, as a result of a colder heating season in 2007 compared with 2006, partially offset by higher operating, depreciation, and property tax expenses. Yankee Gas' Regulatory ROE was 6.6 percent for the 12 months ended June 30, 2007. As a result of its recent rate case settlement agreement, management expects Yankee Gas' Regulatory ROE to improve over the second half of 2007 and that it will be able to earn between 9 percent and 10 percent in 2008.

For the distribution segment of the regulated companies, a summary of changes in CL&P, PSNH and WMECO electric KWH sales and Yankee Gas firm natural gas sales for the second quarter and first half of 2007 as compared to 2006 on an actual and weather normalized basis is as follows:

For the Three Months Ended June 30, 2007 Compared to June 30, 2006

Electric

	CL&P		**PSNH**		**WMECO**		**Total**	
	Percentage Increase	**Weather Normalized Percentage Increase/ (Decrease)**	**Percentage Increase/ (Decrease)**	**Weather Normalized Percentage Increase/ (Decrease)**	**Percentage Increase/ (Decrease)**	**Weather Normalized Percentage Increase/ (Decrease)**	**Percentage Increase/ (Decrease)**	**We Norn Perc Inc (Dec**
Residential	2.6 %	1.2 %	0.8 %	1.3 %	1.3 %	- %	2.0 %	
Commercial	2.4 %	2.0 %	1.1 %	1.9 %	1.7 %	1.4 %	2.1 %	
Industrial	0.1 %	(0.1)%	(1.5)%	(0.8)%	(3.4)%	(3.6)%	(0.9)%	
Other	9.0 %	9.0 %	20.9 %	20.9 %	2.8 %	2.8 %	9.3 %	
Total	2.2 %	1.4 %	0.5 %	1.2 %	0.3 %	(0.3)%	1.6 %	

For the Six Months Ended June 30, 2007 Compared to June 30, 2006

Electric

	CL&P		**PSNH**		**WMECO**		**Total**	
	Percentage	**Weather Normalized Percentage**	**Percentage**	**Weather Normalized Percentage**	**Percentage Increase/**	**Weather Normalized Percentage**	**Percentage Increase/**	**We Norn Perc**

	Increase/ (Decrease)	**Increase/ (Decrease)**	**Increase/ (Decrease)**	**Increase/ (Decrease)**	**(Decrease)**	**Increase/ (Decrease)**	**(Decrease)**	**Inc (Dec**
Residential	3.9 %	1.5 %	3.4 %	2.3 %	2.9 %	0.8 %	3.7 %	
Commercial	1.5 %	1.0 %	2.1 %	2.0 %	2.0 %	1.6 %	1.7 %	
Industrial	(3.9)%	(4.0)%	(2.8)%	(2.4)%	(3.8)%	(3.9)%	(3.6) %	
Other	14.1 %	14.1 %	7.9 %	7.9 %	0.6 %	0.6 %	12.7 %	
Total	1.9 %	0.6 %	1.6 %	1.3 %	1.0 %	0.1 %	1.7 %	

NU Enterprises: NU Enterprises continues to wind down its few remaining wholesale contracts and energy services activities.

NU's condensed consolidated statements of income for all periods presented classify the operations for the following as discontinued operations:

- A portion of the former Woods Electrical Co., Inc. (Woods Electrical), which was sold in April of 2006,
- Select Energy Services, Inc. (SESI), which was sold in May of 2006,
- Northeast Generation Company (NGC), which was sold in November of 2006 (including certain components of Northeast Generation Services Company (NGS)), and
- Holyoke Water Power Company's (HWP) Mt. Tom generating plant, which was sold in November of 2006.

NU Enterprises earned $2.5 million in the second quarter of 2007 and $7.4 million in the first half of 2007, compared with losses of $14.3 million in the second quarter of 2006 and $76.9 million in the first half of 2006. NU Enterprises earnings in the first half of 2007 were primarily due to higher than expected margins, and the favorable resolution of certain contingencies from the SESI sale related to a contract to complete a cogeneration facility, partially offset by a $1.2 million negative mark-to-market on the few remaining wholesale contracts.

In the first half of 2006, NU Enterprises recorded losses related to Select Energy's retail marketing business, which was sold on June 1, 2006. The retail marketing business lost $1.1 million in the second quarter of 2006 and $72.7 million for the first half of 2006. These results reflect the operating margins of the retail marketing business being more than offset by its ongoing expenses and an approximately $33 million negative after-tax adjustment (approximately $53 million pre-tax) to record the retail marketing business at fair value less cost to sell.

Parent and Affiliates: Parent company and affiliates earned $1.5 million in the second quarter of 2007 and earned $7.6 million in the first half of 2007, compared with earnings of $3 million in the second quarter of 2006 and $0.9 million in the first half of 2006. The decline in second quarter 2007 earnings from 2006 was primarily attributable to a $2 million after-tax gain associated with the sale of NU s former investment in Globix Corporation, a telecommunications company, in the second quarter of 2006. NU recorded no such gain in 2007. The improvement in the results for the first half of 2007 compared with 2006 is due to higher interest income earned on cash balances that NU affiliates borrowed from NU parent through the NU Money Pool (Pool) or that NU parent invested in outside money market funds, offset by interest on NU parent long-term debt. Earnings on the Pool investments are eliminated in consolidation along with the corresponding interest expense for the Pool borrowers. The company expects that NU parent earnings will decline over the remaining quarters of 2007 as the NU parent's cash was used to pay taxes in March of 2007 related to the sale of the competitive generation business and will continue to be used to make equity investments in the regulated companies to support capital expenditures.

Future Outlook

NU continues to project consolidated 2007 earnings of between $1.30 per share and $1.55 per share. The company's earnings guidance does not include the impact of marking-to-market NU Enterprises' wholesale energy contracts, which have significantly decreased in number since 2006.

Regulated Companies: NU continues to project 2007 earnings of between $0.80 per share and $0.90 per share in its distribution and generation segment and between $0.50 per share and $0.60 per share at the transmission segment of the regulated companies. Among other assumptions, those projections assume that the regulated companies achieve their projected level of capital expenditures, particularly in the transmission segment, in accordance with their present schedule.

Parent and Affiliates: NU continues to project 2007 earnings of between zero and $0.05 per share for NU parent and affiliates.

NU Enterprises: NU projects modestly positive results at NU Enterprises in 2007. This earnings guidance does not include the impact of marking-to-market NU Enterprises' wholesale energy contracts which have significantly decreased in number since 2006. For additional information regarding sensitivity analyses of NU Enterprises' remaining wholesale energy positions, see Item 3, "Quantitative and Qualitative Disclosures About Market Risk," included in this report on Form 10-Q.

Long-Term Growth Rate: NU continues to project that it can achieve compounded annual EPS growth of between 10 percent and 14 percent over 2006 annual EPS for the period from 2007 through 2011, with much of the EPS growth concentrated in 2007 and 2008. For this comparison, 2006 annual EPS represents 2006 regulated company and parent and affiliates results of $1.16 per share, which excludes a $0.48 per share benefit associated with an Internal Revenue Service private letter ruling affecting CL&P in 2006. That growth rate is based on a compounded annual growth of approximately 7 percent in the regulated companies' distribution and generation segment rate base and approximately 23 percent in the regulated companies' transmission segment rate base. This EPS growth rate assumes appropriate regulatory approvals and timely rate treatment for the company's electric transmission and distribution investments and natural gas distribution investments. It also assumes the company achieves its projected levels of capital expenditures and rate base growth in accordance with its present schedule.

Liquidity

Consolidated: NU's liquidity position continues to benefit from the proceeds the company received from the sale of NU Enterprises' competitive generation assets in November of 2006 and the issuance of $300 million of CL&P long-term debt. At June 30, 2007, NU parent had no borrowings under its $500 million revolving credit line, the regulated companies (specifically Yankee Gas) had $45 million of long-term borrowings under their $400 million revolving credit line, and CL&P had no sales of accounts receivable under its $100 million accounts receivable sales facility. The company had $138.8 million of cash and cash equivalents on hand at June 30, 2007.

The company's level of consolidated cash on hand declined in the first half of 2007 primarily as a result of the payment of $398.5 million in federal and state income taxes in the first quarter of 2007. Of that amount, $177.2 million was paid by CL&P, $47.9 million was paid by WMECO, $7.1 million was paid by PSNH and $166.3 million was paid by other NU companies. CL&P and WMECO accrued the majority of these tax obligations in 2000 upon the sale of the generation assets to NGC, but due to the intercompany nature of the sales, they were allowed to defer any federal or state income tax payments by those companies at that time. It was not until NU sold NGC to an unaffiliated third party in November of 2006 that CL&P and WMECO were required to pay these deferred tax obligations.

Primarily as a result of those tax payments, NU had negative consolidated operating cash flows in the first half of 2007 of $37.5 million. Excluding the tax payments of $398.5 million and $55 million made in the first quarter of 2007 and 2006, respectively, NU's cash flows from operations in the first half of 2007 totaled $361 million, compared with $268.1 million in the first half of 2006. The improved 2007 cash flows excluding the tax payments were due to an expected reduction in regulatory refunds related to CTA amounts refunded to CL&P ratepayers during the first half of 2006 as compared to the first half of 2007. In addition to lower regulatory refunds paid, the regulated companies made lower payments to the Yankee Companies for decommissioning and closure costs in the first half of 2007 as compared to 2006, primarily as a result of the extension of the collection period for CYAPC's decommissioning and closure costs. Also impacting cash flows from operations were lower cash payments related to Select Energy s derivative contracts and changes in working capital items related to the divestiture of the NU Enterprises' businesses in 2006. Cash flows from operations are expected to improve further in the second half of 2007 as the PSNH and Yankee Gas rate increases take effect on July 1, 2007.

Overall, NU's cash position is expected to continue to fluctuate in 2007. NU forecasts capital expenditures of approximately $1.3 billion and common and preferred dividends of approximately $125 million in 2007. As a result, NU and the regulated companies expect they will need to further borrow under their credit facility later in 2007 and issue approximately $310 million in additional long-term debt later in 2007. CL&P sold $300 million of bonds in March of 2007. Also, NU parent will need to repay $150 million of debt on June 1, 2008.

NU's senior unsecured debt is rated Baa2, BBB-, and BBB with a stable outlook by Moody's Investors Service (Moody's), Standard & Poor's (S&P) and Fitch Ratings (Fitch), respectively. Fitch reaffirmed its ratings and stable outlook on NU, CL&P, PSNH and WMECO on May 10, 2007. If NU's senior unsecured debt ratings were to be reduced to a sub-investment grade level by either Moody's or S&P, Select Energy could, under its present contracts, be asked to provide approximately $86.9 million of collateral or letters of credit (LOCs) to various unaffiliated counterparties and approximately $22.4 million to several independent system operators and unaffiliated local distribution companies (LDCs) in each case at June 30, 2007. If such a downgrade were to occur, NU would currently be able to provide that collateral.

NU paid common dividends of $58.5 million in the first half of 2007, compared with $54 million in the first half of 2006. The increase primarily reflects a 7.1 percent increase in NU's common dividend that took effect in the third quarter of 2006. On May 7, 2007, the NU Board of Trustees approved a dividend of $0.20 per share, a 6.7 percent increase over the previous dividend rate, payable on September 28, 2007 to shareholders of record as of September 1, 2007.

Management expects to continue its current policy of dividend increases, subject to the approval of the NU Board of Trustees and the company's future earnings and cash requirements. In general, the regulated companies pay approximately 60 percent of their cash earnings to NU in the form of common dividends. In the first half of 2007, CL&P, PSNH, WMECO, and Yankee Gas paid $39.6 million, $15.4 million, $6.4 million, and $12.7 million, respectively, in common dividends to NU. In the first half of 2007, NU parent contributed $215 million of equity to CL&P, $29.5 million to PSNH, $4.8 million to WMECO and $52.7 million to Yankee Gas. At June 30, 2007, NU parent had $391.3 million invested in the Pool and will continue to infuse equity into the regulated companies as their capital needs and structure dictate. At June 30, 2007, the Pool had a balance of $114.6 million invested externally.

NU'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 to it. The Federal Power Act limits the payment of dividends by CL&P, PSNH and WMECO to their retained earnings balances, and PSNH is required to reserve an additional amount under certain Federal Energy Regulatory Commission (FERC) hydroelectric license conditions. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas. CL&P, PSNH, WMECO and Yankee Gas also have a leverage restriction under their revolving credit agreement.

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 cost of removal, the allowance for funds used during construction (AFUDC) related to equity funds and the capitalized portion of pension expense or income. NU's subsidiary companies cash capital expenditures totaled $491.1 million in the first half of 2007, compared with $380.7 million in the first half of 2006. NU's first half of 2007 cash capital expenditures included $353.2 million by CL&P, $79.5 million by PSNH, $21.9 million by WMECO, $29.2 million by Yankee Gas, and $7.3 million by other NU subsidiaries. The increase in NU's regulated companies cash capital expenditures was primarily the result of higher transmission capital expenditures, particularly at CL&P.

Regulated Companies: The regulated companies maintain a $400 million credit line that expires on November 6, 2010. There were $45 million of long-term borrowings by Yankee Gas outstanding under that facility at June 30, 2007.

In addition to its revolving credit facility, CL&P has an arrangement with a financial institution under which CL&P can sell up to $100 million of accounts receivable and unbilled revenues. There were no amounts outstanding under that facility at June 30, 2007. For more information regarding CL&P's sale of receivables, see Note 1F, "Summary of Significant Accounting Policies - Sale of Customer Receivables," to the condensed consolidated financial statements.

NU Enterprises: Most of the working capital and LOCs required by NU Enterprises are currently used to support the few remaining wholesale contracts. As NU Enterprises' remaining wholesale contracts expire or are exited, its liquidity requirements will continue to decline. Four of NU Enterprises five remaining wholesale contracts in the PJM power pool expired on May 31, 2007. The remaining PJM contract will expire on May 31, 2008. NU Enterprises' only other significant wholesale contracts include a long-term contract with the New York Municipal Power Association (NYMPA) which expires in 2013 and a long-term contract to purchase the output from a generating plant in New England through 2012.

Business Development and Capital Expenditures

Consolidated: NU's consolidated capital expenditures, including cost of removal, AFUDC, and the capitalized portion of pension expense or income, totaled $531.3 million in the first half of 2007, compared with $420.3 million in the first half of 2006. These amounts include $4.1 million and $19.3 million for the first half of 2007 and 2006, respectively, that are unrelated to the regulated companies. Capital expenditures for the regulated companies are expected to total $1.3 billion in 2007, including $750 million in the transmission segment. The $1.3 billion in regulated company capital expenditures is approximately $100 million higher than previously forecasted, primarily due to transmission capital projects, as well as a modest increase in distribution and generation segment capital expenditures.

Regulated Companies:

Transmission Segment: Transmission rate base totaled approximately $1.2 billion at June 30, 2007, compared with approximately $1 billion at December 31, 2006. Transmission rate base is expected to total approximately $1.45 billion at the end of 2007. In 2007, CL&P, PSNH and WMECO are currently projecting transmission segment capital expenditures of approximately $650 million, $80 million, and $20 million, respectively, totaling $750 million. The $750 million in transmission capital expenditures is approximately $65 million higher than previously forecasted, primarily due to the identification of opportunities to complete transmission segment projects in southwest Connecticut and other projects earlier than anticipated and the addition of other transmission segment capital projects to be completed in 2007. A summary of transmission segment capital expenditures by company in the first half of 2007 and 2006 is as follows (millions of dollars):

	For the Six Months Ended June 30,	
	2007	**2006**
CL&P	$ 267.4	$ 176.9
PSNH	22.2	11.7

WMECO		7.1		5.9
Other		0.6		0.2
Totals	$	297.3	$	194.7

The increase in transmission segment capital expenditures in the first half of 2007 as compared with 2006 primarily relates to CL&P, which is undertaking a significant enhancement of its transmission system in southwest Connecticut. CL&P has three major projects under construction in southwest Connecticut, which are on or ahead of schedule and on budget, including:

- A 69-mile, 115 kilovolt (KV)/345 KV transmission project from Middletown to Norwalk, Connecticut. CL&P's portion of this project is estimated to cost approximately $1.05 billion. Although this project is expected to be completed by the end of 2009, construction of the project is ahead of schedule, and the company is reviewing the project schedule to determine whether it can be completed at an earlier date. At June 30, 2007, CL&P's portion of this project was approximately 34 percent complete and by late July 2007, was estimated to be approximately 38 percent complete. CL&P has capitalized $360.9 million associated with this project;

- A two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), construction of which began in October of 2006. Glenbrook Cables is required for the growing electric demand in the area and is budgeted at approximately $183 million. This project is on schedule for a second half of 2008 in-service date. At June 30, 2007, this project was approximately 36 percent complete, and CL&P has capitalized $71.9 million associated with this project; and

- The replacement of the existing 138 KV undersea cable between Connecticut and Long Island for which, permitting, contracting and cable manufacturing are complete or well underway. CL&P and the Long Island Power Authority (LIPA) jointly filed plans with the Department of Environmental Protection (DEP) to replace this 11-mile undersea electric transmission line between Norwalk and Northport - Long Island, New York and each own approximately 50 percent of the line. CL&P's portion of the project is estimated to cost $72 million. Final DEP permits have been received and CL&P expects to receive the United States Army Corps of Engineers permit in the third quarter of 2007. Marine construction activities are scheduled to commence in

October of 2007, and a 2008 project in-service date is expected. At June 30, 2007, the project was approximately 41 percent complete, and CL&P has capitalized $19 million associated with this project.

As part of a larger regional system plan, NU, New England Independent System Operator (ISO-NE) and National Grid have begun planning a series of upgrades to the 345 KV transmission system connecting Massachusetts, Rhode Island and Connecticut in a comprehensive study called the New England East-West Solution (NEEWS). NEEWS includes three interdependent 345 KV NU projects that work together to address the region's transmission needs: 1) the Greater Springfield 345 KV Reliability Project, 2) the Central Connecticut Reliability Project, and 3) the Interstate Reliability Project. A fourth project, National Grid's Rhode Island Reliability Project, is also included in NEEWS. NU and National Grid have entered into a formal agreement to plan and permit these projects and expect to work with ISO-NE on the technical review of these projects during the remainder of 2007 with the completion of the ISO-NE review in early 2008. The filing of the first project applications with the various state siting authorities will occur shortly after receiving the technical approvals from ISO-NE. At this time, the company expects to complete construction of these projects in 2013. NU has not yet completed a detailed estimate of the total cost for NEEWS and the timing of expenditures is highly dependent upon receipt of technical and siting approvals. NU currently expects its share of the NEEWS 345 KV projects to cost between approximately $850 million and approximately $1.1 billion. The range of the project's cost will increase significantly if more underground construction is required than is currently included in that range.

In addition to NEEWS, studies also have identified that transmission infrastructure upgrades are required for the 115 KV system in the Springfield, Massachusetts area. This WMECO project, referred to as the Springfield 115 KV Upgrade, will improve reliability and set the stage for enhancing access to competitively priced power and renewable energy. WMECO expects to receive technical approval from ISO-NE by the end of 2007. Once technical approval is received, WMECO expects to begin to file applications for the Springfield 115 KV Upgrade with the Massachusetts siting agencies. At this time, WMECO expects the Springfield 115 KV Upgrade to cost between $250 million and $350 million and to complete the project by the end of 2010, which will increase WMECO's capital expenditures significantly from the amounts previously forecasted.

In October of 2006, the $340 million Bethel, Connecticut to Norwalk project was completed and energized and has operated reliably since then. As a result, in addition to improving reliability, the company believes the completion of that project is the primary reason why congestion costs have declined by approximately 50 percent in Connecticut so far this year through late July of 2007 (from approximately $120 million through late July of 2006 to approximately $60 million over the same period of 2007).

Distribution and Generation Segment: In 2007, CL&P, PSNH, WMECO and Yankee Gas are currently projecting distribution segment (and in the case of PSNH, also its generation segment) capital expenditures of $290 million, $125 million, $35 million, and $65 million, respectively, totaling $515 million, which includes a modest increase from the amounts previously forecasted. A summary of distribution and generation segment capital expenditures by company in the first half of 2007 and 2006 is as follows (millions of dollars):

	For the Six Months Ended June 30,	
	2007	**2006**
CL&P	$ 128.0	$ 100.7
PSNH	56.3	52.1
WMECO	16.4	14.3
Yankee Gas	29.1	37.6
Other	0.1	1.6
Totals	$ 229.9	$ 206.3

The first half of 2007 capital expenditures at Yankee Gas included $9.3 million spent on its LNG storage and production facility in Waterbury, Connecticut, which is capable of storing the equivalent of 1.2 bcf of natural gas. In late June of 2007, Yankee Gas began storing liquefied natural gas in the LNG storage facility for use by customers in the 2007/2008 heating season. The facility was completed in July of 2007 and is expected to be on budget with a final cost of approximately $108 million. The capital cost of this facility has been included in Yankee Gas' rates as of July 1, 2007.

Primarily due to increases in expected PSNH reliability capital investments and Yankee Gas system integrity projects, it is expected that the five-year distribution capital spending projection will increase when that projection is updated in the third quarter of 2007. The CL&P rate case could also increase this projection.

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 ensures the reliability of the New England transmission system, administers the independent system operator tariff (ISO Tariff), subject to FERC approval, and oversees the efficient and competitive functioning of the regional wholesale power market.

Transmission - Wholesale Rates: Wholesale transmission revenues are based on rates and formulas that are approved by the FERC. Most of NU s wholesale transmission revenues are collected under the FERC Electric Tariff No. 3, Open Access Transmission Tariff (OATT). Tariff No. 3 includes the Regional Network Service (RNS) and Local Network Service (LNS) rate schedules. The RNS rate, administered by ISO-NE, is set on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, administered by NU, is set on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities. The LNS rate provides for an annual true-up to total actual costs, which ensures that NU recovers its total (both regional and local) revenue requirements.

FERC ROE Decision: As a result of the preliminary October 31, 2006 FERC ROE decision, the company recorded an estimated regulatory liability for refunds of $25.6 million as of December 31, 2006. During the first half of 2007, the company completed the customer refunds that were calculated in accordance with the compliance filing, required by the FERC ROE decision and refunded approximately $23.9 million to regional, local and localized transmission customers. The $1.7 million positive pre-tax difference ($1 million after-tax) between the estimated regulatory liability recorded and the actual amount refunded was recognized in pre-tax earnings in the second quarter of 2007.

Pursuant to an October 31, 2006 FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on

July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. NU and the other RTO members are currently evaluating this FERC order. NU's transmission companies may be required to make additional refunds and currently estimates such pre-tax refunds to be potentially approximately $3.5 million (approximately $2 million after-tax). NU's distribution companies would receive a net after-tax benefit of approximately $0.4 million as a result of these refunds. The estimated refunds and benefits totaling approximately $1.6 million after-tax were not recorded at June 30, 2007.

<u>Legislative Matters</u>

Connecticut:

2007 Legislation: On June 4, 2007, "An Act Concerning Electricity and Energy Efficiency," (Energy Efficiency Act) was signed into law by Connecticut Governor Rell. Among other provisions, the Energy Efficiency Act:

- Requires electric distribution companies to file annual integrated resources plans for DPUC approval;
- Provides wide-ranging incentives for customers to reduce consumption, particularly during peak load periods;
- Requires CL&P and other Connecticut electric distribution companies to file proposals with the DPUC in January of 2008 to build cost-of-service peaking generation facilities;
- Requires the DPUC to allow CL&P and other Connecticut electric distribution companies to buy generation assets that are for sale in Connecticut, if their purchase is in the public interest;
- Requires the DPUC to decouple electric and natural gas distribution revenues from sales volumes in future rate cases in an effort to align the interests of customers and the utilities in pursuit of conservation and energy efficiency; and
- Requires CL&P and other Connecticut electric distribution companies to offer metering to customers, which will support time-based pricing.

As part of the state's budget, $85 million was approved for energy efficiency and renewable programs. The fund is allocated 80 percent to CL&P and 20 percent to UI. This will result in an annual increase in energy efficiency spending by CL&P of approximately $20 million to $25 million beginning in 2008. CL&P anticipates it will be allowed to earn incentives on these higher levels of spending.

The company continues to evaluate the implications of the Energy Efficiency Act on CL&P, Yankee Gas and the Connecticut electricity marketplace. See Note 1I, "Summary of Significant Accounting Policies - Other Income, Net," to the condensed consolidated financial statements for further information.

New Hampshire:

2007 Legislation: On May 14, 2007, New Hampshire Governor Lynch signed a law establishing renewable portfolio standards for electricity sold in the state and ultimately requiring that 25 percent of the electricity sold to retail customers have direct ties to renewable sources by 2025. The renewable sourcing requirements begin in 2008 and increase each year to reach 25 percent by 2025. PSNH will be required to comply with these standards which will primarily result in the purchase of RECs. The company expects that the additional costs incurred in meeting this new requirement will be recovered through PSNH's energy service rates. PSNH continues to evaluate the impact of these standards.

Additionally, on July 17, 2007, New Hampshire Governor Lynch signed a law which:

- Directs the NHPUC to encourage upgrades to the transmission system in northern New Hampshire;
- Directs the state Site Evaluation Committee to develop new rules for siting renewable facilities by October 1, 2007; and
- Adds utility ownership of distributed renewable generation and demand-side management to the topics that the legislature s standing State Energy Policy Committee should examine.

The company continues to evaluate the impact of this law on PSNH.

<u>Regulatory Developments and Rate Matters</u>

Connecticut - CL&P:

Distribution Rates: On June 29, 2007, CL&P filed a Notice of Intent to file an application with the DPUC to raise distribution rates by approximately $189 million effective on January 1, 2008, and approximately $22 million effective in January of 2009. In its application, CL&P cited a weak Regulatory ROE, which has been significantly lower than its 9.85 percent authorized Regulatory ROE since the end of 2004, and has requested an authorized Regulatory ROE of 11 percent. The notice also cited the December 31, 2007 expiration of $30 million of refunds per year to customers for four years totaling $120 million from previous overrecoveries and the need to upgrade CL&P's aging distribution facilities. CL&P filed its full application on July 30, 2007 and expects the DPUC to hold hearings on the proposal in the late fall of 2007 and to issue a decision in early 2008.

As required by the Energy Efficiency Act, CL&P's rate case includes a proposal to implement partial distribution revenue decoupling from the volume of electricity sales using a revenue per customer adjustment mechanism. On July 31, 2007, the DPUC opened a separate docket to investigate distribution revenue decoupling. Decoupling determinations in this docket are expected to be included in CL&P's rate case. It is unclear what decoupling mechanism will be adopted by the DPUC and what impact it will have on CL&P.

Time-of-Use Rates: On March 30, 2007, CL&P filed a metering compliance plan with the DPUC that would meet the DPUC's objective of offering time-of-use rates to all CL&P customers. CL&P's filing discussed the technology, implementation options and costs comparing an open advanced metering infrastructure (AMI) system deployed on a geographic basis to a fixed automated metering reading (AMR) network system deployed on a usage-based priority schedule. The plan provided for full deployment by 2010. On July 2, 2007, CL&P filed a revised AMI plan consistent with the requirements of the Connecticut Energy Efficiency Act described above. The revised plan provided a more incremental deployment schedule based on customer interest and allowed for future DPUC input at various milestones. In both plans, CL&P requested cost recovery through its federally mandated congestion costs (FMCC) mechanism. As there is a wide range of outcomes in the technology that could be used and the schedule and level of implementation of AMI, the cost of implementing AMI could vary greatly.

Standard Service Procurement and Rates: On July 1, 2007, CL&P implemented a 5 percent average decrease in the overall bills for residential and small commercial and industrial customers who receive standard service as a result of lower power procurement costs, reduced FMCC and a decline in CL&P s transmission charge. The average standard service generation rate decreased from $0.11241 per KWH to $0.10791 per KWH. At the same time, CL&P implemented a 0.9 percent increase in overall supplier of last resort standard service rates due to an increase in the generation service charge (GSC) from $0.11359 per KWH to $0.11571 per KWH. Large commercial and industrial customers are served through provider of last resort rates. CL&P is fully recovering the cost of its standard service and supplier of last resort service.

On February 2, 2007, CL&P filed with the DPUC a semi-annual FMCC reconciliation filing for the period January 1, 2006 through December 31, 2006. A decision on CL&P s semi-annual FMCC reconciliation filing is expected to be issued in August of 2007.

Procurement Fee Rate Proceedings: By law, CL&P was allowed to collect a fixed procurement fee of 0.50 mills per KWH from customers who purchased TSO service from 2004 through the end of 2006. On December 8, 2005, a draft decision was issued by the DPUC which accepted the methodology proposed by CL&P to calculate the variable portion (incentive portion) of the procurement fee and authorized payment of $5.8 million for its 2004 incentive fee. A final decision, which had been scheduled for December 28, 2005, was delayed by the DPUC, and the DPUC re-opened the docket to review additional testimony.

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On April 17, 2007, CL&P filed an application with the DPUC for approval of incentive payments for the years 2005 and 2006. The incentive portion of the procurement fee earned for 2005 is $6 million and for 2006 is $5.5 million. The DPUC rejected this application and directed CL&P to refile after a DPUC decision on the 2004 case.

Management continues to believe that recovery of the $5.8 million asset related to CL&P's 2004 incentive payment, which was reflected in 2005 earnings, is probable. No amounts have been recorded for the 2005 or 2006 incentive portions of CL&P's procurement fee. The procurement fee expired at the end of 2006.

Independence and Energy Efficiency Acts: Pursuant to Public Act 05-01, "An Act Concerning Energy Independence," the DPUC conducted an RFP process and selected three generating projects that would be eligible to sign contracts for differences with CL&P and UI for a total of 782 MW of capacity. The process also selected one demand response project for 5 MW. The contracts for differences 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. The contracts are for a period of up to 15 years. These contracts have been signed and are currently awaiting approval by the DPUC, with a decision scheduled for August of 2007. CL&P and UI have filed a sharing agreement with the DPUC under which they will share the costs and benefits of these contracts, with 80 percent to CL&P and 20 percent to UI, regardless of whether CL&P or UI signed the contract. CL&P s portion of the costs and benefits of these contracts will be paid by or refunded to CL&P s customers. The capacity contracts for differences are being challenged by intervenors, including the OCC.

Public Act 07-242, "An Act Concerning Electricity and Energy Efficiency" (Energy Efficiency Act), provides for the electric distribution companies to sign cost-of-service based contracts for the energy associated with these projects, for term lengths equivalent to the associated contracts for differences. These energy contracts must be approved by the DPUC after a finding that they will stabilize the cost of electricity to Connecticut ratepayers. A long-term contract to purchase energy from a project that is also under a contract for differences could result in CL&P consolidating these projects into its financial statements. CL&P would seek to recover from customers any costs that result from consolidation of a project.

In May of 2007, CL&P and UI 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. The agreement has been approved by the DPUC. The costs to CL&P under this agreement will depend on the quantities purchased and the price of energy, are subject to another similar sharing agreement with CL&P and UI and are currently estimated to be approximately $15 million annually from 2010 to 2024. The Connecticut Clean Energy Fund has approved, for further consideration by the DPUC, 11 more renewable energy projects of different designs totaling approximately 160 MW, of which the DPUC is expected to approve up to 125 MW. Contracts for these projects will also be subject to the sharing agreement with UI. CL&P and UI are required to provide the DPUC with their comments relating to the accounting and economic implications of contracts with these projects in August of 2007. It is currently unknown which projects will be approved by the DPUC. CL&P's share of the future costs of such projects will be paid by CL&P's customers. The effects of these contracts on CL&P's financial statements and their ultimate cost cannot be estimated at this time.

Connecticut - Yankee Gas:

Yankee Gas Rate Relief: On June 29, 2007, the DPUC approved a rate case settlement agreement between Yankee Gas, the OCC and the DPUC's Prosecutorial Division that resulted in an annualized increase of $22.1 million or 4.2 percent in Yankee Gas' base rates effective on July 1, 2007. The $22.1 million increase is net of pipeline and commodity cost savings primarily from completion of Yankee Gas' new $108 million 1.2 bcf, LNG storage facility. The decision allows Yankee Gas to recover the costs related to its LNG storage facility and higher costs to distribute natural gas and includes an authorized Regulatory ROE of 10.1 percent. Yankee Gas' new rates do not reflect the revenue decoupling required by the Energy Efficiency Act, since the rate case was filed well before the legislation was passed.

New Hampshire:

Delivery Service Rate Case: On May 25, 2007, the NHPUC approved a distribution and transmission rate case settlement agreement between PSNH, the NHPUC staff and the OCA. The settlement agreement included, among other items, a transmission cost tracking mechanism, effective on July 1, 2006, to be reset annually, and an allowed distribution ROE of 9.67 percent. The allowed generation ROE of 9.62 percent was unaffected. The permanent settlement agreement provided for a $37.7 million estimated annualized increase ($26.5 million for distribution and $11.2 million estimated for transmission) beginning on July 1, 2007, along with the previous $24.5 million annualized interim distribution rate increase that was effective on July 1, 2006. The $37.7 million includes a one year revenue increase of approximately $9 million related to additional revenues to recoup the difference between the interim and permanent rates for the period July 1, 2006 through June 30, 2007. Overall, PSNH's average retail rates decreased 0.4 percent on July 1, 2007 primarily due to a lower energy service rate. An additional delivery revenue increase of approximately $3 million will take effect on January 1, 2008, with a final estimated rate decrease of approximately $9 million scheduled for July 1, 2008. The settlement agreement enables PSNH to fund a $10 million annual Reliability Enhancement Program and more adequately fund its Major Storm Cost Reserve.

The pre-tax earnings impact of the approximately $9 million of additional revenues related to the July 1, 2006 through June 30, 2007 time period was or is being recognized as follows: approximately $4.5 million attributable to 2006 retail transmission expense was recognized in the second quarter of 2007; $3 million attributable to distribution costs from July 1, 2006 through June 30, 2007 will be recognized over the 12-month period beginning on July 1, 2007 and the remaining $1.5 million of revenue will be captured as part of the 2007 retail transmission tracker and offset by an equal amount of retail transmission expenses.

Contingent Matters: The items summarized below contain contingencies that may have an impact on the company's net income, financial position or cash flows. See Note 6A, "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 30, 2007, CL&P filed its 2006 CTA and System Benefits Charge (SBC) reconciliation, which compared CTA and SBC revenues to revenue requirements, with the DPUC. Management expects a decision in this docket from the DPUC by the end of 2007 and does not expect the outcome to have a material adverse impact on CL&P's net income, financial position or cash flows.

- *Purchased Gas Adjustment:* In 2005 and 2006, the DPUC issued decisions regarding Yankee Gas Purchased Gas Adjustment (PGA) clause charges and required an audit of approximately $11 million in previously recovered PGA revenues associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. The audit has concluded, and a final report has been submitted. Management believes the unbilled sales and revenue adjustments and resulting charges to customers through the PGA clause for this period were appropriate and that the appropriateness of the PGA charges to customers for the time period under review will be approved.

- *SCRC/ES Reconciliation and Rates:* On May 1, 2007, PSNH filed its 2006 stranded cost recovery charge (SCRC)/default energy service (ES) reconciliation with the NHPUC which is expected to be adjudicated in the third quarter of 2007. Management does 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.

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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. Management does not expect the outcome of the DPU's review of these filings to have a material adverse impact on WMECO's net income, financial position or cash flows.

<u>NU Enterprises Divestitures</u>

NU has exited substantially all of its competitive businesses. NU Enterprises continues to wind down its few remaining wholesale contracts and energy services activities.

Wholesale Marketing Business: During the first half of 2007, NU Enterprises continued to manage its remaining obligations in the PJM power pool and under a long-term contract with the NYMPA. Four of the remaining five PJM wholesale contracts expired on May 31, 2007 with the remaining contract due to expire on May 31, 2008. In addition to the PJM and NYMPA 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. Based on the current value of this non-derivative contract, when combined with the net wholesale derivative contract portfolio that has been marked-to-market at June 30, 2007 at a value of negative $89.6 million, management believes, under present conditions, that the estimated total cash cost at June 30, 2007 to exit the remaining wholesale marketing business is less than $50 million.

Retail Marketing Business: On June 1, 2006, Select Energy sold its retail marketing business and paid approximately $24.4 million in 2006 and will pay $14.8 million by the end of 2007 under that sales agreement. These amounts were and are included in other current liabilities on the accompanying condensed consolidated balance sheets.

Competitive Generation Business: NU completed the sale of NU Enterprises' competitive generation assets on November 1, 2006.

Energy Services Businesses: Most of NU Enterprises' energy services businesses were sold in 2005 and 2006. In the second quarter of 2007, the energy services businesses recorded an after-tax gain of approximately $2.5 million related the favorable resolution of certain contingencies from the SESI sale related to a contract to complete a cogeneration facility.

In connection with the sale of the retail marketing business, the competitive generation business and certain of the energy services businesses, NU provided various guarantees and indemnifications to the purchasers of these businesses. See Note 6F, "Commitments

and Contingencies - Guarantees and Indemnifications," to the condensed consolidated financial statements for information regarding these items.

NU Enterprises Contracts

Wholesale Derivative Contracts: At June 30, 2007 and December 31, 2006, the fair value of NU Enterprises' wholesale derivative assets and derivative liabilities, which are subject to mark-to-market accounting (excluding the non-derivative contract described above), are as follows:

(Millions of Dollars)		**June 30, 2007**		**December 31, 2006**
Current wholesale derivative assets	$	56.2	$	43.6
Long-term wholesale derivative assets		9.1		22.3
Current wholesale derivative liabilities		(79.7)		(82.3)
Long-term wholesale derivative liabilities		(75.2)		(110.1)
Portfolio position	$	(89.6)	$	(126.5)

Numerous factors could either positively or negatively affect the realization of the wholesale net fair value amounts in cash. These factors include the amounts paid or received to exit some or all of these contracts, the volatility of commodity prices until the contracts are exited or expire, the outcome of future transactions, the performance of counterparties, and other factors.

Select Energy has policies and procedures requiring all of its wholesale 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 energy contracts are identified and segregated in the table of fair value of contracts at June 30, 2007 and December 31, 2006. 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. Currently, Select Energy also has a 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 the years 2012 through 2013. Broker quotes for electricity at locations for which Select Energy has entered into transactions are generally available through the year 2011.

Generally, valuations of short-term 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 contracts are less certain. Accordingly, there is a risk that contracts will not be realized at the amounts recorded.

At June 30, 2007 and December 31, 2006, the sources of the fair value of wholesale contracts are included in the following tables:

(Millions of Dollars)	Fair Value of Wholesale Contracts at June 30, 2007			
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	$ (1.4)	$ (4.4)	$ 0.2	$ (5.6)
Prices provided by external sources	(22.1)	(30.4)	(7.0)	(59.5)
Model-based	-	1.2	(25.7)	(24.5)
Totals	$ (23.5)	$ (33.6)	$ (32.5)	$ (89.6)

(Millions of Dollars)	Fair Value of Wholesale Contracts at December 31, 2006			
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	$ (6.9)	$ (11.2)	$ (1.9)	$ (20.0)
Prices provided by external sources	(32.2)	(44.8)	(12.7)	(89.7)
Model-based	0.4	3.5	(20.7)	(16.8)
Totals	$ (38.7)	$ (52.5)	$ (35.3)	$ (126.5)

For the three and six months ended June 30, 2007, the changes in fair value of these contracts are included in the following table:

(Millions of Dollars)	For the Three Months Ended June 30, 2007 Total Portfolio Fair Value	For the Six Months Ended June 30, 2007 Total Portfolio Fair Value
Fair value of wholesale contracts outstanding at the beginning of the period	$ (96.9)	$ (126.5)
Contracts realized or otherwise settled during the period	11.9	39.0
Changes in fair value recorded in fuel, purchased and net interchange power	(4.6)	(2.1)
Fair value of wholesale contracts outstanding at the end of the period	$ (89.6)	$ (89.6)

Counterparty Credit: 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 continuing review by the company. 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 to economic, regulatory or other conditions. At June 30, 2007, Select Energy's counterparty credit exposure to wholesale and trading counterparties was approximately 3 percent collateralized, approximately 20 percent was rated BBB- or better and approximately 77 percent was non-rated. The composition of Select Energy's credit portfolio has shifted from being largely investment grade-rated to being mostly non-rated. This is largely due to the exit from the wholesale New England and retail portfolios and the expiration of PJM obligations. The bulk of the non-rated credit exposure is comprised of one counterparty (97 percent of total) that is a creditworthy, non-rated public entity. Select Energy was provided $2.6 million and $0.1 million of counterparty deposits at June 30, 2007 and December 31, 2006, respectively.

Critical Accounting Policies and Estimates Update

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 the financial statements of NU. Management communicates to and discusses with NU's 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 NU 2006 Form 10-K and certain accounting policies and estimates were updated in the NU First Quarter 2007 Form 10-Q. There have been no further material changes with regard to these critical accounting policies and estimates except as follows:

Pension Benefits: NU's subsidiaries participate in the Northeast Utilities Service Company Retirement Plan (Plan) covering substantially all regular NU employees. NU estimates the year end (December 31st) prepaid or accrued pension asset or obligation based on an actuarial valuation as of the beginning of the year (January 1st), adjusted for known changes during the year such as actual earnings, interest rate levels, expenses incurred and benefits paid during the year. This estimated year end balance is also used to estimate the following year's related pension income or expense and the prepaid or accrued pension asset obligation recorded through the first quarter. This estimate is adjusted in the second quarter of the following year based on an actuarial valuation using actual data as of January 1st of that year. An actuarial valuation as of January 1, 2007 was completed in the second quarter of 2007, resulting in a second quarter increase to the prepaid pension asset of $19.8 million with a decrease to the regulatory asset for deferred benefits of $17.3 million and an increase to accumulated other comprehensive income of $1.5 million, net of tax.

<u>Cost of Living Adjustment (COLA) Remeasurement:</u> On May 4, 2007, NU's Board of Trustees approved a COLA, which increased retiree pension benefits for certain participants in the Plan. NU estimated the effect of the COLA and determined that it was significant enough to require a remeasurement of the Plan's assets and benefit obligation. The COLA was announced on May 8, 2007 at the annual meeting of NU's shareholders and the benefit obligation was remeasured on that date.

The COLA increased the Pension Plan's benefit obligation by $40 million, which was reflected as a prior service cost and as a decrease in the funded status of the Pension Plan. This amount will be amortized over the 12-year average remaining service lives of employees. However, the $40 million increase in the Pension Plan's benefit obligation (decrease in the prepaid funded status) as a result of the COLA was more than offset by positive adjustments of approximately $100 million related to other aspects of the remeasurement, including favorable 2007 Pension Plan asset performance through May 8, 2007 and an increase in the discount rate from 5.9 percent at December 31, 2006 to 6.0 percent at the remeasurement date. On a combined basis, as a result of the May 8, 2007 remeasurement, the net prepaid pension asset increased by approximately $60 million.

As a result of the remeasurement, regulatory assets related to deferred benefit costs decreased by $51.4 million and accumulated other comprehensive income increased by $4.3 million, net of tax.

The pre-tax, pre-capitalization earnings impact of this remeasurement is to decrease annual 2007 pension expense by approximately $7 million. The positive after-tax impact on 2007 earnings is approximately $3 million.

For additional information regarding these changes, see Note 9, "Pension Benefits and Postretirement Benefits Other Than Pensions," to the condensed consolidated financial statements.

Expected Contributions and Forecasted Expense: As a result of the completion of the actuarial valuation as of January 1, 2007 and the COLA remeasurement, the forecasted expense for the Plan has changed since last reported in NU's 2006 Form 10-K. Based on current Plan assumptions, NU currently estimates that the expected contributions and forecasted expense along with the amounts included in NU's 2006 Form 10-K are as follows (in millions):

	Pension Plan - Current Estimate		**Pension Plan - NU's 2006 Form 10-K**	
Year	**Expected Contributions**	**Forecasted Expense**	**Expected Contributions**	**Forecasted Expense**
2007	None	$17.3	None	$26.2
2008	None	$18.9	None	$18.8
2009	None	$ 5.4	None	$ 8.9

Other Matters

Contractual Obligations and Commercial Commitments: For updated information regarding NU's contractual obligations and commercial commitments at June 30, 2007, see Note 6C, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the condensed consolidated financial statements.

HWP Environmental Matters: The company remains in the process of evaluating additional potential remediation requirements at a river site in Massachusetts containing tar deposits. HWP is at least partially responsible for this site, and substantial remediation activities at this site have already been conducted. HWP first established a reserve for this site in 1994. Since that time, HWP has expensed approximately $13 million of which $12.2 million has been spent and $0.8 million remains in the reserve. HWP s reserve is based on its most recent site assessment and estimate of required remediation costs. The ultimate remediation requirements will depend, among other things, on the level and extent of the remaining tar required to be removed, and the extent of HWP s responsibility. These matters are the subject of ongoing discussions with the Massachusetts Department of Environmental Protection and may change from time-to-time. HWP's share of the remediation costs related to this site is not recoverable from ratepayers. At this time, management cannot predict the outcome of this matter or its ultimate effect on NU. Any additional increase to the environmental remediation reserve for this site would be recorded in earnings in future periods when it is estimable and probable, and potential increases may be material. There were no changes to the environmental reserve in the second quarter of 2007.

Consolidated Edison, Inc. Merger Litigation: Certain gain and loss contingencies exist with regard to the merger agreement between NU and Consolidated Edison, Inc. (Con Edison) and the related litigation.

In 2001, Con Edison advised NU that it was unwilling to close its merger with NU on the terms set forth in the parties' 1999 merger agreement (Merger Agreement). In March of 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

In a 2005 opinion, a panel of three judges at the Second Circuit held that the shareholders of NU had no right to sue Con Edison for its alleged breach of the parties' Merger Agreement. This ruling left intact the remaining claims between NU and Con Edison for breach of contract, which include NU's claim for recovery of costs and expenses of approximately $32 million and Con Edison's claim for damages of "at least $314 million." NU's request for a rehearing was denied in 2006. NU opted not to seek review of this ruling by the United States Supreme Court. In April of 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. NU's motion asserts that NU is entitled to a judgment in its favor with respect to this claim based on the undisputed material facts and applicable law. The matter is fully briefed and awaiting a decision. At this time, NU cannot predict the outcome of this matter or its ultimate effect on NU.

For further information regarding other commitments and contingencies, see Note 6, "Commitments and Contingencies," to the condensed consolidated financial statements.

Accounting Standards Issued But Not Yet Adopted:

A.

Fair Value Measurements: On September 15, 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is expected to be applied to fair value measurements of derivative contracts that are subject to mark-to-market accounting and to other assets and liabilities that are reported at fair value or subject to fair value measurements. SFAS No. 157 is expected to be implemented prospectively with any adjustments to fair value reflected as a cumulative effect adjustment to the opening balance of retained earnings as of January 1, 2008. The company is evaluating the potential impact of SFAS No. 157 on its financial statements.

B.

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in earnings. The company is evaluating the measurement options available under SFAS No. 159, which will be effective in the first quarter of 2008.

Forward Looking Statements: This discussion and analysis includes statements concerning NU's expectations, plans, objectives, future financial performance 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. In some cases the reader can identify these forward looking statements by words such as "estimate," "expect," "anticipate," "intend," "plan," "believe," "forecast," "should," "could," and similar expressions. Forward looking statements involve risks and uncertainties that may cause actual results or outcomes to differ materially from those included in the forward looking statements. Factors that may cause actual results to differ materially from those included in the forward looking statements include, but are not limited to, actions or inactions by local, 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 or 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 the remaining electricity positions, actions of rating agencies, subsequent recognition, derecognition and measurement of tax positions, and other presently unknown or unforeseen factors.

Other risk factors are detailed from time to time in the company's reports to the SEC, including the factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2006. Any forward looking statement speaks only as of the date on which such statement is made and the company undertakes no obligation to update the information contained in any forward looking statements to reflect developments or circumstances occurring after the statement is made.

Web Site: Additional financial information is available through NU's 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, 2007:

	Income Statement Variances (Millions of Dollars) 2007 over/(under) 2006			
	Second Quarter	Percent	Six Months	Percent
Operating Revenues:	$ (269)	(16) %	$ (712)	(19) %
Operating Expenses:				
Fuel, purchased and net interchange power	(305)	(27)	(778)	(29)
Other	(23)	(9)	(94)	(16)
Restructuring and impairment charges	(3)	(100)	(8)	(98)
Maintenance	10	22	18	21
Depreciation	4	6	8	7
Amortization	(2)	(a)	(55)	(95)
Amortization of rate reduction bonds	3	7	6	7
Taxes other than income taxes	3	5	(1)	(1)
Total operating expenses	(313)	(20)	(904)	(24)
Operating Income	44	60	192	(a)
Interest expense, net	(1)	(2)	(1)	(1)
Other income, net	-	(2)	-	(2)
Income/(loss) from continuing operations before income tax (benefit)/expense	45	(a)	193	(a)
Income tax expense/(benefit)	13	(a)	64	(a)
Preferred dividends of subsidiary	-	-	-	-
Income/(loss) from continuing operations	32	(a)	129	(a)
Income/(loss) from discontinued operations	(6)	(70)	(17)	(93)
Net Income	$ 26	(a) %	$ 112	(a) %

(a) Percentage greater than 100.

Comparison of the Second Quarter of 2007 to the Second Quarter of 2006

Operating Revenues

Operating revenues decreased $269 million in 2007 primarily due to lower revenues from NU Enterprises ($175 million) and lower revenues from the regulated companies ($94 million).

NU Enterprises' revenues decreased $175 million due to the exit from significant components of the competitive businesses during the latter part of 2006.

Revenues from the regulated companies decreased $94 million due to lower distribution segment revenues ($118 million), partially offset by higher transmission segment revenues ($23 million). Distribution segment revenues decreased $118 million primarily due to lower electric distribution revenues ($125 million), partially offset by higher gas distribution revenues ($7 million). Transmission segment revenues increased $23 million primarily due to a higher transmission investment base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Lower electric distribution revenues include 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 ($137 million). The distribution revenue tracking components decrease of $137 million is primarily due to the pass through of lower energy supply costs ($56 million), lower CL&P revenue associated with the recovery of FMCC ($51 million) and a decrease in PSNH s SCRC revenues mainly as a result of a rate decrease that went into effect July 1, 2006 ($32 million). The tracking mechanisms allow for rates to be changed periodically with over-collections refunded to customers or under-collections collected from customers in future periods.

The distribution component of the electric distribution segment which flows through to earnings increased $12 million primarily due to an increase in retail rates ($10 million) and an increase in retail sales ($2 million). The distribution retail electric sales were positively affected by weather impacts in 2007 as compared with 2006. Retail KWH electric sales increased by 1.6 percent in 2007 compared with 2006 (a 1.2 percent increase on a weather normalized basis).

The decrease in electric distribution revenues is partially offset by higher gas distribution revenues of $7 million primarily due to higher sales volumes as a result of a colder winter in 2007. Firm gas sales increased 11.0 percent in 2007 compared with 2006. On a weather normalized basis, firm gas sales increased 6.0 percent.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $305 million in 2007 primarily due to lower costs at NU Enterprises ($195 million) and lower costs at the regulated companies ($110 million). NU Enterprises' fuel expenses decreased due to the exit from significant components of the competitive businesses. Fuel expense from the regulated companies decreased primarily due to lower fuel expenses at CL&P and PSNH ($108 million), mainly as a result of a decrease in standard offer supply costs as a result of a reduction in load caused by customer migration, partially offset by higher 2007 supply prices.

Other Operation

Other operation expenses decreased $23 million in 2007 primarily due to lower regulated company distribution and transmission segment expenses ($14 million) and lower NU Enterprises' expenses ($9 million).

Lower regulated company distribution and transmission segment expenses of $14 million are primarily due to lower reliability must run (RMR) expenses at CL&P ($26 million), partially offset by higher retail transmission expenses at WMECO and PSNH ($8 million) and higher EIA expenses to be recovered through the FMCC deferral at CL&P ($4 million).

Restructuring and Impairment Charges

See Note 2, "Restructuring Charges," to the condensed consolidated financial statements for a description and explanation of these charges.

Maintenance

Maintenance expenses increased $10 million in 2007 primarily due to higher regulated company distribution and transmission segment expenses ($8 million).

Higher regulated company distribution and transmission segment expenses of $8 million are primarily due to higher overhead line, line transformer and station equipment maintenance expenses at CL&P and WMECO ($8 million).

Depreciation

Depreciation increased $4 million in 2007 primarily due to higher distribution and transmission depreciation expense ($4 million) as a result of higher plant balances from the ongoing construction program.

Amortization

Amortization decreased $2 million in 2007 for the regulated companies' distribution segments primarily due to PSNH distribution ($20 million), partially offset by higher amortization for CL&P distribution ($13 million) and WMECO distribution ($5 million). The PSNH decrease is primarily due to lower ES overrecoveries, the deferral of retail transmission costs, and lower amortization levels of stranded costs.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $3 million in 2007. 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 $3 million in 2007 primarily due to higher payroll-related taxes ($2 million) and higher Connecticut gross earnings tax ($2 million).

Interest Expense, Net

Interest expense decreased $1 million, primarily due to lower interest at NU Enterprises ($6 million), partially offset by higher interest for the regulated company distribution and transmission segments ($4 million). The higher regulated company distribution and transmission segment interest is primarily due to higher interest at CL&P as a result of the March 2007 debt issuance.

Income Tax Expense/(Benefit)

Income tax expense increased $13 million due primarily to an increase in pre-tax earnings, partially offset by a decrease in the effective tax rate. The decrease in the effective tax rate was primarily due to lower flow through regulatory amortizations. In the prior

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year, flow through regulatory amortizations were higher as a result of the regulatory recovery of tax expense associated with nondeductible acquisition costs.

Income/(Loss) from Discontinued Operations

See Note 3, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements for a description and explanation of the discontinued operations.

Comparison of the First Six Months of 2007 to the First Six Months of 2006

Operating Revenues

Operating revenues decreased $712 million in 2007 primarily due to lower revenues from NU Enterprises ($622 million) and lower revenues from the regulated companies ($90 million).

NU Enterprises' revenues decreased $622 million due to the exit from significant components of the competitive businesses during the latter part of 2006.

Revenues from the regulated companies decreased $90 million due to lower distribution segment revenues ($136 million), partially offset by higher transmission segment revenues ($46 million). Distribution segment revenues decreased $136 million primarily due to lower electric distribution revenues ($144 million), partially offset by higher gas distribution revenues ($7 million). Transmission segment revenues increased $46 million primarily due to a higher transmission investment base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Lower electric distribution revenues include 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 ($163 million). The distribution revenue tracking components decrease of $163 million is primarily due to lower CL&P revenue associated with the recovery of FMCC ($108 million), a decrease in PSNH s SCRC revenues mainly as a result of a rate decrease that went into effect July 1, 2006 ($71 million) and the pass through of lower energy supply costs ($10 million), partially offset by higher retail transmission revenues ($27 million). The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of the electric distribution segment which flows through to earnings increased $19 million primarily due to an increase in retail rates ($12 million) and an increase in retail sales ($7 million). The distribution retail electric sales were positively affected by weather impacts in 2007 as compared with 2006. Retail KWH electric sales increased by 1.7 percent in 2007 compared with 2006 (a 0.8 percent increase on a weather normalized basis).

The decrease in electric distribution revenues is partially offset by higher gas distribution revenues of $7 million primarily due to higher sales volumes as a result of a colder winter in 2007. Firm gas sales increased 11.0 percent in 2007 compared with 2006. On a weather normalized basis, firm gas sales increased 4.4 percent.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $778 million in 2007 primarily due to lower costs at NU Enterprises ($672 million) and lower costs at the regulated companies ($107 million). NU Enterprises' fuel expenses decreased due to the exit from significant components of the competitive businesses.

Other Operation

Other operation expenses decreased $94 million in 2007 primarily due to lower NU Enterprises' expenses ($89 million) and lower regulated company distribution and transmission segment expenses ($4 million).

NU Enterprises' expenses decreased $89 million primarily due to the exit from significant components of the competitive business.

Restructuring and Impairment Charges

See Note 2, "Restructuring Charges," to the condensed consolidated financial statements for a description and explanation of these charges.

Maintenance

Maintenance expenses increased $18 million in 2007 primarily due to higher regulated company distribution and transmission segment expenses ($14 million).

Higher regulated company distribution and transmission segment expenses of $14 million are primarily due to higher overhead line, underground line, structure, and line transformer maintenance at CL&P, WMECO and PSNH, and higher boiler plant maintenance at PSNH.

Depreciation

Depreciation increased $8 million in 2007 primarily due to higher distribution and transmission depreciation expense ($9 million) as a result of higher plant balances from the ongoing construction program.

Amortization

Amortization decreased $55 million in 2007 for the regulated companies' distribution segments primarily due to PSNH distribution ($78 million), partially offset by higher amortization for WMECO distribution ($10 million) and CL&P distribution ($9 million). The PSNH decrease is primarily due to lower ES overrecoveries, lower amortization levels of stranded costs, and the deferral of retail transmission costs.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $6 million in 2007. 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 decreased $1 million in 2007 primarily due to lower property taxes for CL&P.

Interest Expense, Net

Interest expense decreased $1 million, primarily due to lower interest at NU Enterprises ($12 million), partially offset by higher interest for the regulated company distribution and transmission segments ($11 million). The higher regulated company distribution and transmission segment interest is primarily due to higher interest at CL&P, as a result of higher debt resulting from the June 2006 and March 2007 debt issuances.

Income Tax Expense/(Benefit)

Income tax expense increased $64 million due primarily to an increase in pre-tax earnings, partially offset by a decrease in the effective tax rate. The decrease in the effective tax rate was primarily due to lower flow through regulatory amortizations, partially offset by changes in prior year tax reserves resulting from the favorable settlement of a state refund claim. In the prior year, flow through regulatory amortizations were higher as a result of the regulatory recovery of tax expense associated with nondeductible acquisition costs.

Income/(Loss) from Discontinued Operations

See Note 3, "Assets Held for Sale and 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 2007 Form 10-Q and the NU 2006 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, 2007:

	Income Statement Variances (Millions of Dollars) 2007 over/(under) 2006			
	Second Quarter	Percent	Six Months	Percent
Operating Revenues:	$ (69)	(7) %	$ (30)	(2) %
Operating Expenses:				
Fuel, purchased and net interchange power	(85)	(14)	(61)	(5)
Other operation	(26)	(16)	(37)	(12)
Maintenance	6	27	7	17
Depreciation	2	4	4	6
Amortization	12	(a)	14	(a)
Amortization of rate reduction bonds	2	8	4	7
Taxes other than income taxes	4	13	5	6
Total operating expenses	(85)	(10)	(64)	(4)

Operating Income		16	33		34	31
Interest expense, net		3	10		10	17
Other income, net		1	21		(2)	(15)
Income/(loss) from continuing operations before income tax		14	59		22	33
Income tax expense/(benefit)		6	91		13	86
Net Income/(Loss)	$	8	48 %	$	9	18 %

(a) Percent greater than 100.

<u>Comparison of the Second Quarter of 2007 to the Second Quarter of 2006</u>

Operating Revenues

Operating revenues decreased $69 million due to lower distribution business revenues ($91 million), partially offset by higher transmission business revenues ($22 million).

The distribution business revenue decrease of $91 million is primarily due to the components of revenues, which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($97 million). The distribution business revenue tracking components decreased $97 million primarily due to a decrease in revenues associated with the recovery of FMCC charges ($51 million) and lower TSO related revenues ($43 million), as a result of the pass through of lower energy supply costs. The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of revenues which impacts earnings increased $6 million as a result of the rate increase effective January 1, 2007 and higher retail sales. Retail sales increased 2.2 percent in 2007 compared to the same period in 2006.

Transmission business revenues increased $22 million primarily due to a higher rate base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $85 million primarily due to a decrease in standard offer supply costs ($78 million) and lower other purchased power costs ($14 million), partially offset by higher deferred fuel costs of $7 million, all of which are included in regulatory commission-approved tracking mechanisms. The $78 million decrease in supply costs was due primarily to a reduction in load caused primarily by customer migration, partially offset by higher 2007 supply prices. These supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply Standard Service and Last Resort Service load through a competitive solicitation process.

Other Operation

Other operation expenses decreased $26 million primarily due to lower RMR costs ($26 million), which are tracked and recovered through the FMCC, partially offset by higher Energy Independence Act (EIA) expenses which will also be recovered through the FMCC deferral mechanism ($4 million).

Maintenance

Maintenance expenses increased $6 million primarily due to higher expenses related to overhead lines ($3 million), line transformers ($1 million), underground lines and station equipment.

Depreciation

Depreciation expense increased $2 million primarily due to higher utility plant balances.

Amortization of Regulatory Liabilities, Net

Amortization of regulatory liabilities, net increased $12 million primarily due to higher amortization related to the recovery of transition charges ($10 million) and higher SFAS No. 109 amortization ($3 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 $4 million primarily due to higher gross earnings taxes ($2 million), higher payroll-related taxes ($1 million) and higher property taxes ($1 million).

Interest Expense, Net

Interest expense, net increased $3 million primarily due to higher interest on long-term debt ($7 million) mainly as a result of $300 million of new debt issued in March of 2007 and $250 million of new debt issued in June of 2006, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($2 million) and lower short-term debt interest ($1 million).

Other Income, Net

Other income, net increased $1 million, primarily due to higher AFUDC income ($3 million) and the lower equity in earnings recorded in 2006 on the decommissioning write-off of CT Yankee ($2 million), partially offset by a lower TSO procurement fee ($3 million).

Income Tax Expense

Income tax expense increased $6 million due to increases in the effective tax rate and pre-tax earnings. The increase in the effective tax rate (from 27 to 32 percent) was primarily due to lower current year state tax credits and higher projected pre-tax earnings.

Comparison of the First Six Months of 2007 to the First Six Months of 2006

Operating Revenues

Operating revenues decreased $30 million due to lower distribution business revenues ($72 million), partially offset by higher transmission business revenues ($42 million).

The distribution business revenue decrease of $72 million is primarily due to the components of revenues, which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($79 million). The distribution business revenue tracking components decreased $79 million primarily due to a decrease in revenues associated with the recovery of FMCC charges ($108 million), partially offset by higher TSO related revenues ($27 million), as a result of the pass through of higher energy supply costs. The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of revenues which impacts earnings increased $7 million as a result of the rate increase effective January 1, 2007 and higher retail sales. Retail sales increased 1.9 percent in 2007 compared to the same period in 2006.

Transmission business revenues increased $42 million primarily due to a higher rate base and higher operating expenses, which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $61 million primarily due to a decrease in standard offer supply costs ($157 million) and lower other purchased power costs ($32 million), partially offset by an increase of $127 million resulting from a reduction in supply and reliability cost credit deferrals, all of which are included in regulatory commission-approved tracking mechanisms. The $157 million decrease in supply costs was due primarily to a reduction in load caused primarily by customer migration, partially offset by higher 2007 supply prices. These supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply Standard Service and Last Resort Service load through a competitive solicitation process. The $127 million increase resulting from a reduction in supply and reliability cost credit deferrals was largely the result of more timely collection of supply costs from customers due to a change in customer supply rates from average annual rates to average semi-annual rates.

Other Operation

Other operation expenses decreased $37 million primarily due to lower RMR costs ($50 million), which are tracked and recovered through the FMCC, partially offset by higher Energy Independence Act (EIA) expenses which will also be recovered through the FMCC deferral mechanism ($6 million), higher uncollectible accounts expense ($4 million) and higher administrative expenses ($3 million).

Maintenance

Maintenance expenses increased $7 million primarily due to higher expenses related to overhead lines ($2 million), underground lines ($2 million), structures ($1 million), and line transformers ($1 million).

Depreciation

Depreciation expense increased $4 million primarily due to higher utility plant balances.

Amortization of Regulatory Liabilities, Net

Amortization of regulatory liabilities, net increased $14 million primarily due to higher amortization related to the recovery of transition charges ($6 million), higher SFAS No. 109 amortization ($6 million) and a higher system benefit charge deferral ($2 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $4 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 $5 million primarily due to higher gross earnings taxes ($4 million) and higher property taxes ($1 million).

Interest Expense, Net

Interest expense, net increased $10 million primarily due to higher interest on long-term debt ($10 million) mainly as a result of $250 million of new debt issued in June of 2006 and $300 million of new debt issued in March of 2007, higher FIN 48 interest ($2 million) and higher FMCC deferral interest ($2 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, primarily due to a lower TSO procurement fee ($6 million), partially offset by higher Energy Independence Act (EIA) incentives ($2 million) and higher AFUDC income ($2 million).

Income Tax Expense

Income tax expense increased $13 million due primarily to increases in the effective tax rate and pre-tax earnings. The increase in the effective tax rate (from 22 to 31 percent) was primarily due to changes in prior year tax reserves resulting from the favorable settlement of a state refund claim and lower current year state tax credits.

LIQUIDITY

Net cash flows from operations decreased by $24.4 million from $82.8 million for the first six months of 2006 to $58.4 million for the first six months of 2007. CL&P s operating cash flows declined in the first six months of 2007 primarily as a result of the payment in March of 2007 of $177.2 million in federal and state income taxes and a higher level of payments to suppliers related to purchased power which were made in the first six months of 2007 as compared to 2006. CL&P s tax obligation was due to the fact that the sale of the generation assets from CL&P to NGC in 2000 did not trigger federal or state income tax payments by those companies at that time. It was not until these assets were sold to an unaffiliated third party in November of 2006 that CL&P was required to pay this deferred tax obligation. These decreases were partially offset by $153.2 decline in regulatory refunds to CL&P ratepayers and lower payments made to the Yankee Companies for decommissioning and closure costs in 2007 as compared to 2006, primarily as a result of the extension of the collection period for CYAPC s decommissioning and closure costs.

Capital expenditures described herein are cash capital expenditures and exclude cost of removal, AFUDC related to equity funds and the capitalized portion of pension expense or income. CL&P's capital expenditures totaled $353.2 million in the first six months of 2007, compared with $240 million in the first six months of 2006. This increase is primarily due to higher transmission capital expenditures.

On March 27, 2007, CL&P closed on the sale of $150 million of 10-year bonds carrying a coupon rate of 5.375 percent and on the sale of $150 million of 30-year bonds carrying a coupon rate of 5.75 percent.

Additionally, CL&P has an arrangement with a financial institution under which CL&P can sell up to $100 million of accounts receivable and unbilled revenues. At June 30, 2007, there were no amounts outstanding under that facility. Financing activities for the six months ended June 30, 2007 included a capital contribution from NU parent in the amount of $215 million. Financing activities also included the payment of $39.6 million in dividends to NU during the first six months of 2007 compared to $31.9 million during the first six months of 2006.

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 2007 Form 10-Q and the NU 2006 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, 2007:

	Income Statement Variances (Millions of Dollars) 2007 over/(under) 2006			
	Second Quarter	Percent	Six Months	Percent
Operating Revenues:	$ (44)	(15) %	$ (83)	(14) %
Operating Expenses:				
Fuel, purchased and net interchange power	(22)	(15)	(21)	(7)
Other operation	4	8	14	15
Maintenance	-	-	4	12
Depreciation	1	9	2	9
Amortization	(19)	(a)	(78)	(a)
Amortization of rate reduction bonds	1	6	1	6
Taxes other than income taxes	1	9	1	5
Total operating expenses	(34)	(14)	(77)	(14)
Operating Income	(10)	(23)	(6)	(9)

Interest expense, net		-	-			-	-		
Other income, net		(1)	(50)			(1)	(50)		
Income/(loss) before income tax		(11)	(34)			(7)	(17)		
Income tax expense/(benefit)		(11)	(67)			(12)	(59)		
Net Income/(Loss)	$	-	-	%	$	5	26	%	

(a) Percentage greater than 100.

Comparison of the Second Quarter of 2007 to the Second Quarter of 2006

Operating Revenues

Operating revenues decreased $44 million primarily due to lower distribution business revenue ($46 million), partially offset by higher transmission business revenue ($1 million).

The distribution business revenue decrease of $46 million is primarily due to the components of revenues, which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($51 million). The distribution revenue tracking components decrease of $51 million is primarily due to a decrease in the SCRC revenue ($32 million) mainly as a result of a rate decrease effective July 1, 2006, lower wholesale revenues ($14 million) and the pass through of lower energy supply costs ($9 million), partially offset by higher retail transmission revenues ($3 million). The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of PSNH s retail rates which impacts earnings increased $5 million, as a result of the rate increase effective July 1, 2006 and higher sales. Retail sales increased 0.5 percent in 2007 compared to the same period of 2006.

Transmission business revenues increased $1 million primarily due to a higher transmission investment base and higher operating expenses, which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power decreased $22 million primarily due to customers migrating from default service to a third party energy supplier.

Other Operation

Other operation expenses increased $4 million primarily due to higher retail transmission expenses ($2 million) and higher Energy Assistance Program (EAP) expenses ($2 million).

Depreciation

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

Amortization of Regulatory Assets

Amortization of regulatory assets decreased $19 million primarily due to lower ES over recoveries in the second quarter of 2007 as compared to the second quarter of 2006 ($10 million), the deferral of retail transmission costs, including specified 2006 costs as allowed under the PSNH rate settlement, through the Transmission Cost Adjustment Mechanism (TCAM) ($7 million), and lower amortization levels of stranded costs, which is consistent with PSNH s recovery of non-securitized stranded costs in June 2006 ($2 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $1 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 payroll-related taxes.

Other Income, Net

Other income, net decreased $1 million primarily due to lower AFUDC income, as a result of decreased eligible construction work in progress (CWIP), higher short-term debt and a lower portion of CWIP being subject to the equity rate.

Income Tax Expense

Income tax expense decreased $11 million due to lower pre-tax earnings and a decrease in the effective tax rate (from 52 to 26 percent). The decrease in the effective tax rate was due to an increase in tax credits, lower state income tax expense, and lower flow through regulatory amortizations. The increase in tax credits results from a full year of production tax credits at the Northern Wood Power Project (NWPP). State tax expense was higher in the prior year due to an increase in unitary taxable income resulting from the sale of generation assets. In the prior year, flow through regulatory amortizations were higher as a result of the regulatory recovery of tax expense associated with nondeductible acquisition costs.

<u>Comparison of the First Six Months of 2007 to the First Six Months of 2006</u>

Operating Revenues

Operating revenues decreased $83 million primarily due to lower distribution business revenue ($84 million), partially offset by higher transmission business revenue ($1 million).

The distribution business revenue decrease of $84 million is primarily due to the components of revenues, which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($94 million). The distribution revenue tracking components decrease of $94 million is primarily due to a decrease in the SCRC revenue ($71 million) mainly as a result of a rate decrease effective July 1, 2006, lower wholesale revenues ($16 million) and the pass through of lower energy supply costs ($17 million), partially offset by higher SBC revenue ($4 million) and higher retail transmission revenues ($4 million). The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of PSNH s retail rates which impacts earnings increased $10 million, as a result of the rate increases effective July 1, 2006 and higher sales. Retail sales increased 1.6 percent in 2007 compared to the same period of 2006.

Transmission business revenues increased $1 million primarily due to a higher transmission investment base and higher operating expenses, which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power decreased $21 million primarily due to customers migrating from default service to a third party energy supplier.

Other Operation

Other operation expenses increased $14 million primarily due to higher retail transmission expenses ($8 million), higher EAP expenses ($3 million) and higher administrative expenses ($3 million) primarily due to higher employee incentive program costs.

Maintenance

Maintenance expenses increased $4 million primarily due to higher boiler maintenance costs as a result of the planned wood boiler outage ($2 million), and higher structure and overhead line maintenance expenses ($1 million).

Depreciation

Depreciation expense increased $2 million primarily due to higher utility plant balances.

Amortization of Regulatory Assets

Amortization of regulatory assets decreased $78 million primarily due to lower ES over recoveries in the first six months of 2007 as compared to the first six months of 2006 ($33 million), lower amortization levels of stranded costs, which is consistent with PSNH s recovery of non-securitized stranded costs in June 2006 ($33 million) and the deferral of retail transmission costs through the TCAM, which was implemented in 2007 as allowed under the PSNH rate case settlement ($10 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $1 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.

Other Income, Net

Other income, net decreased $1 million primarily due to lower AFUDC income, as a result of decreased eligible CWIP, higher short-term debt and a lower portion of CWIP being subject to the equity rate.

Income Tax Expense

Income tax expense decreased $12 million due to lower pre-tax earnings and a decrease in the effective tax rate (from 51 to 26 percent). The decrease in the effective tax rate was due to an increase in tax credits, lower state income tax expense, and lower flow through regulatory amortizations. The increase in tax credits results from a full year of production tax credits at the NWPP. State tax expense was higher in the prior year due to an increase in unitary taxable income resulting from the sale of generation assets. In the prior year, flow through regulatory amortizations were higher as a result of the regulatory recovery of tax expense associated with nondeductible acquisition costs.

LIQUIDITY

Net cash flows from operations decreased by $63.9 million from $116.5 million for the first six months of 2006 to $52.6 million for the first six months of 2007. The decrease in operating cash flows is primarily due to a significant reduction in approved SCRC rates effective on January 1, 2007 as a result of the completion of PSNH's recovery of its Part 3 non-securitized stranded costs in the second quarter of 2006.

Capital expenditures described herein are cash capital expenditures and exclude cost of removal, AFUDC related to equity funds and the capitalized portion of pension expense. PSNH's capital expenditures totaled $79.5 million in the first six months of 2007 compared to $60.4 million in the first six months of 2006.

Financing activities for the six months ended June 30, 2007 included a capital contribution from NU parent in the amount of $29.5 million as well as the payment of $15.4 million in dividends to NU, compared to $2.5 million and $29.2 million, respectively, during the first six months of 2006.

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 2007 Form 10-Q and the NU 2006 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, 2007:

	Income Statement Variances (Millions of Dollars) 2007 over/(under) 2006			
	Second Quarter	Percent	Six Months	Percent
Operating Revenues:	$ 13	13 %	$ 14	6 %
Operating Expenses:				
Fuel, purchased and net interchange power	(5)	(8)	(22)	(15)
Other operation	8	46	17	51
Maintenance	2	42	2	27
Depreciation	1	24	2	23
Amortization	5	(a)	10	(a)
Amortization of rate reduction bonds	-	-	-	-
Taxes other than income taxes	-	-	-	-
Total operating expenses	11	13	9	4
Operating Income	2	19	5	23

Interest expense, net		-	-		-	-
Other income, net		-	-		-	-
Income/(loss) before income tax		2	37		5	37
Income tax expense/(benefit)		-	-		1	23
Net Income/(Loss)	$	2	75 %	$	4	47 %

(a) Percent greater than 100.

<u>Comparison of the Second Quarter of 2007 to the Second Quarter of 2006</u>

Operating Revenues

Operating revenues increased $13 million due to higher distribution business revenue ($12 million) and higher transmission business revenue ($1 million).

The distribution business revenue increase of $12 million is primarily due to the components of revenues, which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($11 million). The distribution revenue tracking components increased $11 million primarily due to higher retail transmission revenues ($6 million), higher pension tracker and default service true-up revenues ($4 million), and higher transition cost recoveries ($4 million), partially offset by the pass through of lower energy supply costs ($3 million). The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of revenues, which impacts earnings increased $1 million primarily due to the distribution rate increase effective January 1, 2007.

Transmission business revenues increased $1 million primarily due to a higher transmission investment base and higher operating expenses which are recovered 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 purchased power costs ($3 million) and lower default service supply costs ($2 million), which are included in a regulatory commission approved tracking mechanism. Lower purchased power costs of $3 million are the result of lower capacity costs for the Yankee companies' contractual obligations. The default service supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply default service load through a competitive solicitation process. The decrease in these costs is primarily the result of decreased load levels, resulting from customers migrating from default service to a third party energy supplier, during the second quarter of 2007 as compared to the second quarter of 2006.

Other Operation

Other operation expenses increased $8 million primarily due to an increase in retail transmission expenses ($6 million) and higher administrative expenses ($2 million). The increase in retail transmission expenses is mainly due to the deferral, resulting from the regulatory tracking mechanism as a result of the increase in retail transmission revenue rates.

Maintenance

Maintenance expense increased $2 million primarily due to higher tree trimming and maintenance of station equipment and overhead lines.

Depreciation

Depreciation expense increased $1 million primarily due to revised depreciation rates effective January 1, 2007 per the distribution rate settlement and higher utility plant balances.

Amortization of Regulatory Liabilities, Net

Amortization of regulatory liabilities, net increased $5 million primarily due to the deferral of transition costs, as a result of a higher transition charge rate and lower power contract net costs.

<u>Comparison of the First Six Months of 2007 to the First Six Months of 2006</u>

Operating Revenues

Operating revenues increased $14 million due to higher distribution business revenue ($12 million) and higher transmission business revenue ($2 million).

The distribution business revenue increase of $12 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($10 million). The distribution revenue tracking components increased $10 million primarily due to higher retail transmission revenues ($12 million), higher pension tracker and default service true-up revenues ($9 million), higher transition cost recoveries ($7 million), and higher wholesale revenues ($1 million), partially offset by the pass through of lower energy supply costs ($20 million). The tracking mechanisms allow for rates to be changed periodically with over collections refunded to customers or under collections collected from customers in future periods.

The distribution component of revenues which impacts earnings increased $2 million primarily due to the distribution rate increase effective January 1, 2007 and higher retail sales. Retail sales increased 1.0 percent compared to the same period of 2006.

Transmission business revenues increased $2 million primarily due to a higher transmission investment base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $22 million primarily due to lower default service supply costs ($17 million) and lower purchased power costs ($5 million), which are included in a regulatory commission approved tracking mechanism. The default service supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply default service load through a competitive solicitation process. The decrease in these costs is primarily the result of decreased load levels, resulting from customers migrating from default service to a third party energy supplier, and a decrease in the price of electricity paid under these contracts during the first six months of 2007 as compared to the first six months of 2006. Lower purchased power costs of $5 million are the result of lower capacity costs for the Yankee companies' contractual obligations.

Other Operation

Other operation expenses increased $17 million primarily due to an increase in retail transmission expenses ($13 million) and higher administrative expenses ($3 million). The increase in retail transmission expenses is mainly due to the deferral, resulting from the regulatory tracking mechanism as a result of the increase in retail transmission revenue rates.

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Maintenance

Maintenance expense increased $2 million primarily due to higher tree trimming and maintenance of station equipment, structures, and overhead lines.

Depreciation

Depreciation expense increased $2 million primarily due to revised depreciation rates effective January 1, 2007 per the distribution rate settlement and higher utility plant balances.

Amortization of Regulatory Liabilities, Net

Amortization of regulatory liabilities, net increased $10 million primarily due to the deferral of transition costs, as a result of a higher transition charge rate and lower power contract net costs.

Income Tax Expense

Income tax expense increased $1 million due to higher pre-tax earnings, partially offset by a decrease in the effective tax rate (from 43 to 39 percent). The higher effective tax rate in 2006 was primarily caused by a state tax loss that provided no benefit.

LIQUIDITY

Net operating cash flows decreased by $7.3 million from net cash flows provided by operating activities of $1.7 million for the first six months of 2006 to net cash flows used in operating activities of $5.6 million for the first six months of 2007. WMECO s operating cash flows declined in the first six months of 2007 primarily as a result of the payment of $47.9 million in federal and state income taxes. WMECO s tax obligation was due to the fact that the sale of the generation assets from WMECO to NGC in 2000 did not trigger federal or state income tax payments by those companies at that time. It was not until these assets were sold to an unaffiliated third party in November of 2006 that WMECO was required to pay this deferred tax obligation. These tax payments have been partially offset with recoveries from ratepayers due to retail rate adjustments that were effective in January of 2007.

Capital expenditures described herein are cash capital expenditures and exclude cost of removal, AFUDC related to equity funds and the capitalized portion of pension expense or income. WMECO's capital expenditures totaled $21.9 million in the first six months of 2007 compared with $20.8 million in the first six months of 2006. These capital expenditures will significantly increase with the Springfield 115 KV Upgrade, which is expected to cost between $250 million and $350 million and be completed by the end of 2010.

Financing activities for the six months ended June 30, 2007 included a capital contribution from NU parent in the amount of $4.8 million as well as the payment of $6.4 million in dividends to NU, compared to $20.5 million and $4 million, respectively, during the first six months of 2006.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

NU Enterprises utilizes the sensitivity analysis methodology to disclose quantitative information for its 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 management's 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. As the NU Enterprises' businesses are exited, the risks associated with commodity prices are being reduced.

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, 2007, Select Energy has 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 decrease in fair value of $1.6 million and a 10 percent decrease in prices for all products would have resulted in a pre-tax increase in fair value of $0.7 million. A 10 percent increase in energy prices would have resulted in a $9.8 million pre-tax decrease, and a 10 percent decrease in energy prices would have resulted in a $8.9 million pre-tax increase. A 10 percent increase/(decrease) in capacity prices would have resulted in a $2.3 million pre-tax increase/(decrease). A 10 percent increase/(decrease) in ancillary prices would have resulted in a $5.9 million pre-tax increase/(decrease).

The impact of a change in electricity and natural gas prices on wholesale transactions at June 30, 2007 are not necessarily representative of the results that will be realized. These transactions are accounted for at fair value, and changes in market prices impact earnings.

Other Risk Management Activities

Interest Rate Risk Management: NU manages its interest rate risk exposure in accordance with its written policies and procedures by maintaining a mix of fixed and variable rate long-term debt. At June 30, 2007, approximately 90 percent (81 percent including the long-term debt subject to the fixed-to-floating interest rate swap as variable long-term debt) of NU's long-term debt, including fees and interest due for spent nuclear fuel disposal costs, is 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 NU's variable interest rates, including the rate on long-term debt subject to the fixed-to-floating interest rate swap, annual interest expense would have increased by $3.2 million. At June 30, 2007, NU parent maintained a fixed-to-floating interest rate swap 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 NU would incur as a result of non-performance by counterparties pursuant to the terms of its contractual obligations. NU serves a wide variety of customers and suppliers that include IPPs, industrial companies, gas and electric utilities, oil and gas producers, financial institutions, and other energy marketers. Margin accounts exist within this diverse group, and NU realizes 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 NU to manage the portfolio of market risk inherent in those transactions in a manner consistent with the parameters established by NU's risk management process.

Credit risks and market risks at NU Enterprises are monitored regularly by a Risk Oversight Council. The Risk Oversight Council is generally comprised of individuals from outside of the business lines that create or actively manage these risk exposures and functions to ensure compliance with NU's stated risk management policies.

NU tracks and re-balances the risk in its 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.

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 June 30, 2007 and December 31, 2006, Select Energy maintained collateral balances from counterparties of $2.6 million and $0.1 million, respectively. These amounts are included in counterparty deposits on the accompanying condensed consolidated balance sheets. Select Energy also has collateral balances deposited with counterparties of $32.1 million and $48.5 million at June 30, 2007 and December 31, 2006, respectively, which are included in special deposits on the accompanying condensed consolidated balance sheets.

The regulated companies have a lower level of credit risk related to providing regulated electric and gas distribution service than NU Enterprises. However, the regulated companies are subject to credit risk from certain long-term or high-volume supply contracts with energy marketing companies. The 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.

NU has 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 NU s Risk and Capital Committee, comprised of senior NU 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 the company's financial condition or results of operations. The findings of this process are periodically discussed with NU's Finance Committee of the Board of Trustees.

Additional quantitative and qualitative disclosures about market risk are set forth in Part II, Item 7, "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, 2007 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 forms 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 forms 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, 2007 that have materially affected, or are reasonably likely to materially affect internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1.

LEGAL PROCEEDINGS

The company is a party to various legal proceedings. The company has identified these legal proceedings in Part I, Item 3, "Legal Proceedings" in NU's Annual Report on Form 10-K for the year ended December 31, 2006. Other than the update provided below, there have been no material changes with regard to the legal proceedings previously disclosed in NU's most recent Form 10-K.

Enron Bankruptcy Claim

CL&P filed a proof of claim in the sum of $42.9 million against Enron Power Marketing, Inc. (EPMI) in the United States Bankruptcy Court for the Southern District of New York (United States Bankruptcy Court). The claim is for damages resulting from the rejection of the December 22, 2000 electricity purchase agreement between EPMI and CL&P, which was related to an agreement the Connecticut Resource Recovery Authority had entered into with Enron. CL&P and Enron have now agreed to settle the matter by agreeing that the CL&P's claim will have a face value of $19.75 million. The settlement was approved by the DPUC and the United States Bankruptcy Court in April of 2007. Because EPMI is paying less than 100 percent of its unsecured claims, CL&P cannot estimate what percentage of the claim will be paid once the agreement is approved, but the proceeds from the liquidation of the claim will be credited to CL&P's ratepayers.

NRG Bankruptcy

On May 14, 2003, NRG and certain of its affiliates filed for Chapter 11 protection in the United States Bankruptcy Court for the Southern District of New York (Bankruptcy Court). The filing affects relationships between various NU companies and the NRG companies, as follows:

A.

Station Service

NRG has disputed its responsibility to pay for the provision of station service by CL&P to NRG's Connecticut generating plants (approximately $28 million, including late charges). The FERC issued a decision on December 20, 2002 that NRG had agreed that station service from CL&P would be subject to CL&P's applicable retail rates, and that states (i.e., the DPUC) have jurisdiction over the delivery of power to end users even where power is not delivered via distribution facilities. NRG refused CL&P's subsequent demand for payment, and on April 3, 2003, CL&P petitioned the DPUC for a declaratory order enforcing the FERC's December 20, 2002 decision. Prior to the issuance of a decision by the DPUC, NRG filed a petition under Chapter 11 of the United States Bankruptcy Code, staying any further action by the DPUC.

On September 18, 2003, the Bankruptcy Court approved the parties' stipulation to submit the station service issue to arbitration for a determination of liability and damages which will fix CL&P's claim in bankruptcy. The parties are currently pursuing arbitration of the issues in dispute with hearing dates scheduled for the fall of 2007. On December 17, 2003, the DPUC issued a decision in CL&P's rate case that addressed the issue that CL&P had first raised to the DPUC in its April 3, 2003 filing. The DPUC affirmatively stated that CL&P has been appropriately administering its station service rates. Subsequently, however, in unrelated proceedings, the FERC issued a series of orders with conflicting policy direction, which call into question its December 20, 2002 NRG order.

B.

Yankee Gas

On October 9, 2002, NRG informed Yankee Gas that its affiliate, Meriden Gas Turbines, LLC (MGT), was permanently shutting down or abandoning its Meriden power plant project, and requested that Yankee Gas cease its construction activities and begin an orderly wind down of its work relating to the project. Based on NRG's statement that it expected that Yankee Gas would draw on a $16 million LOC, Yankee Gas drew down the full amount of the LOC. On November 12, 2002, MGT filed suit against Yankee Gas in Meriden Superior Court, claiming that Yankee Gas breached the agreement with MGT (MGT Agreement), and seeking a declaratory ruling from the court that Yankee Gas wrongfully drew down the $16 million LOC. In April 2003, Yankee Gas filed its answer to MGT's complaint and asserted a counterclaim to recover its losses arising out of MGT's termination of the MGT Agreement. The parties subsequently reached a settlement in principle of their claims; however, MGT has since requested the court to place the case back on the trial calendar. Yankee Gas filed a motion to enforce the settlement. No trial date is currently scheduled.

C.

Congestion Charges

NRG disputed its responsibility to pay for certain socialized congestion charges under the NEPOOL Transmission Tariff (Tariff) during the term of the Standard Offer Service Wholesale Sales Agreement (Agreement) between CL&P

and NRG, dated as of October 29, 1999. On November 28, 2001, CL&P filed a complaint against NRG in Connecticut Superior Court alleging breach of contract arising from the failure of NRG to pay approximately $28 million of such congestion charges, and from August 2002 through

March 1, 2003, CL&P withheld the past due congestion charges from its monthly payment to NRG, pursuant to contractual provisions allowing the withholding of disputed sums. The case was removed to United States District Court for the District of Connecticut and NRG filed a counterclaim seeking recovery of all amounts CL&P had withheld. CL&P filed a motion for summary judgment on all of the claims in 2004. On July 20, 2007, the court issued its decision, concluding that NRG was contractually obligated to pay CL&P for congestion charges imposed under the Tariff during the term of the Agreement, and found in favor of CL&P (and against NRG) on each of NRG's four counterclaims. NRG has 30 days from the entry of judgment to file an appeal.

ITEM 1A.

RISK FACTORS

The company 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." The company has identified a number of these risk factors in NU's Annual Report on Form 10-K for the year ended December 31, 2006. The company's susceptibility to certain risks, including those discussed in detail in NU's Annual Report on Form 10-K, could exacerbate other risks. These risk factors should be considered carefully in evaluating NU's risk profile. Other than the second and eighth risk factors set forth in NU's Annual Report on Form 10-K, which are updated below, there have been no material changes with regard to the risk factors previously disclosed in NU's most recent Form 10-K.

Increases in Electric and Gas Prices and Focus on Conservation and Self-Generation by Customers and Changes in Legislative and Regulatory Policy May Adversely Impact the Company

The nation's economy has been affected by the significant increases in energy prices, particularly fossil fuels. The impact of these increases has led to increased electricity and natural gas prices for the company s customers, which has increased the focus on conservation, energy efficiency and self-generation on the part of customers and on legislative and regulatory policies. This focus on conservation, energy efficiency and self-generation may result in a decline in electricity and gas sales in our service territories. If any such declines were to occur without corresponding adjustments in rates, then our revenues would be reduced and our future growth prospects would be limited.

In addition, Connecticut, New Hampshire and Massachusetts have each announced policies aimed at increased energy efficiency and conservation. In connection with such policies, all three states have opened proceedings to investigate revenue decoupling as a mechanism to align the interests of customers and utilities relative to conservation. We are unable to predict what mechanisms will ultimately be adopted and their impact on our companies.

Changes in Regulatory or Legislative Policy, Difficulties in obtaining Siting, Design or Other Approvals, Global Demand for Critical Resources, or Environmental or Other Concerns, or Construction of New Generation May Delay Completion of or Displace Our Transmission Projects or Adversely Affect Our Ability to Recover Our Investments or Result in Lower than Expected Rates of Return

The successful implementation of our transmission construction plans is subject to the risk that new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could impact our ability to meet our construction schedule and/or require us to incur additional expenses, and may adversely affect our ability to achieve forecast levels of revenues. In addition, difficulties in obtaining required approvals for construction, or increased cost of and difficulty in obtaining critical resources as a result of global or domestic demand for such resources could cause delays in our construction schedule and may adversely affect our ability to achieve forecasted earnings.

The regulatory approval process for our planned transmission projects encompasses an extensive permitting, design and technical approval process. Various factors could result in increased cost estimates and delayed construction. These include environmental and community concerns and design and siting issues. Recoverability of all such investments in rates may be subject to prudence review at the FERC at the time such projects are placed in service. While the company believes that all such expenses have been and will be prudently incurred, the company cannot predict the outcome of future reviews should they occur.

In addition, to the extent that new generation facilities are proposed or built to address the region s energy needs, the need for our planned transmission projects may be delayed or displaced, which could result in reduced transmission capital investments, reduced earnings, and limit future growth prospects.

The currently planned transmission projects are expected to help alleviate identified reliability issues in southwest Connecticut and to help reduce customers' costs in all of Connecticut. However, if, due to further regulatory or other delays, the projected in-service date for one or more of these projects is delayed, there may be increased risk of failures in the existing electricity transmission system in southwestern Connecticut and supply interruptions or blackouts may occur which could have an adverse effect on our earnings.

The FERC has followed a policy of providing incentives designed to encourage the construction of new transmission facilities, including higher returns on equity and allowing facilities under construction to be placed in rate base before completion. Our projected earnings and growth could be adversely affected were FERC to reduce these incentives in the future below the level presently anticipated.

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, 2007.

ITEM 4.

SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the Annual Meeting of Shareholders of NU held on May 8, 2007, the following ten nominees were elected to serve on the Board of Trustees by the votes set forth below:

		For	Withheld	Total
1.	Richard M. Booth	132,784,870	2,164,917	134,949,787
2.	Cotton M. Cleveland	133,024,104	1,925,683	134,949,787
3.	Sanford Cloud, Jr.	132,784,507	2,165,280	134,949,787
4.	James F. Cordes	132,716,171	2,233,616	134,949,787
5.	E. Gail de Planque	132,004,417	2,945,370	134,949,787
6.	John G. Graham	133,851,762	1,098,025	134,949,787
7.	Elizabeth T. Kennan	131,849,729	3,100,058	134,949,787
8.	Kenneth R. Leibler	133,888,285	1,061,502	134,949,787
9.	Robert E. Patricelli	131,922,051	3,027,736	134,949,787
10.	Charles W. Shivery	133,003,004	1,946,783	134,949,787

11.	John F. Swope	133,166,631	1,783,156	134,949,787

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 2007. The vote ratifying such selection was 133,987,604 votes in favor and 552,792 votes against, and 409,391 abstentions.

NU's shareholders also approved the Amended and Restated Northeast Utilities Incentive Plan. The vote approving such plan was 112,862,393 votes in favor and 8,236,367 votes against, 1,034,618 abstentions and 12,816,409 broker non-votes.

CL&P. In a written Consent in Lieu of an Annual Meeting of Stockholders of CL&P dated June 19, 2007, stockholders 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.

PSNH. In a written Consent in Lieu of an Annual Meeting of Stockholders of PSNH dated June 19, 2007, stockholders 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.

WMECO. In a written Consent in Lieu of an Annual Meeting of Stockholders of WMECO dated June 19, 2007 (WMECO Consent), stockholders 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. In the WMECO Consent stockholders also voted to elect Randy A. Shoop as Vice President and Treasurer and Kerry J. Kuhlman as Vice President-Shared Services, Secretary and Clerk for the ensuing year. 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.

ITEM 6.

EXHIBITS

Document designated with a (*) are filed herewith.

(a)

Listing of Exhibits (NU)

Exhibit No.	Description
*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, 2007
*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, 2007
*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, 2007

Listing of Exhibits (CL&P)

*4

Amendment No. 7 to the Amended and Restated Receivables Purchase and Sales Agreement among CL&P, CRC, CAFCO, Citibank, and CNAI, dated as of July 3, 2007

*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, 2007

*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, 2007

*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, 2007

Listing of Exhibits (PSNH)

*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, 2007

*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, 2007

*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, 2007

Listing of Exhibits (WMECO)

*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, 2007

*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, 2007

*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, 2007

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

Date: August 6, 2007 By /s/ David R. McHale
David R. McHale
Senior Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

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

THE CONNECTICUT LIGHT AND POWER COMPANY
Registrant

Date: August 6, 2007 By /s/ David R. McHale
David R. McHale
Senior Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

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

		PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
		Registrant
Date: August 6, 2007	By	/s/ David R. McHale
		David R. McHale
		Senior Vice President and Chief Financial Officer
		(for the Registrant and as Principal Financial Officer)

SIGNATURE

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

		WESTERN MASSACHUSETTS ELECTRIC COMPANY
		Registrant
Date: August 6, 2007	By	/s/ David R. McHale
		David R. McHale
		Senior Vice President and Chief Financial Officer
		(for the Registrant and as Principal Financial Officer)