NORTHEAST UTILITIES
Form 10-Q
August 07, 2006

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, 2006

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		02-0181050

	PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days:

Yes	No
√	

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, 2006
Northeast Utilities Common stock, $5.00 par value	153,798,675 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

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	Mount Tom generating plant
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company
NU or the company	Northeast Utilities
NU Enterprises	At June 30, 2006, NU s competitive subsidiaries include the merchant energy segment, which is comprised of Select Energy, NGC, NGS and the generation operations of Mt. Tom, and the energy services segment, which is comprised of E.S. Boulos Company, and NGS Mechanical, Inc., which are subsidiaries of NGS and SECI. For further information, see Note 12, "Segment Information," to the condensed consolidated financial statements.
PSNH	Public Service Company of New Hampshire
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
Utility Group	NU s regulated utilities comprised of the electric distribution and transmission businesses of CL&P, PSNH, WMECO, the generation business of PSNH and the gas distribution business of Yankee Gas. For further information, see Note 12 "Segment Information," to the condensed consolidated financial statements.
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

THIRD PARTIES:

CYAPC	Connecticut Yankee Atomic Power Company
ECP	Energy Capital Partners

REGULATORS:

CSC	Connecticut Siting Council
DPUC	Connecticut Department of Public Utility Control
DTE	Massachusetts Department of Telecommunications and Energy
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
EPS	Earnings Per Share
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FMCC	Federally Mandated Congestion Cost
GSC	Generation Service Charge
Hess	Hess Corporation
ISO-NE	New England Independent System Operator
kWh	Kilowatt-Hour
Kv	Kilovolt
LICAP	Locational Installed Capacity
LOCs	Letters of Credit
MW	Megawatt/Megawatts
NU 2005 Form 10-K	The Northeast Utilities and Subsidiaries combined 2005 Form 10-K as filed with the SEC
NYMEX	New York Mercantile Exchange
OCC	Connecticut Office of Consumer Counsel
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
ES	Transition Energy Service/Default Energy Service
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

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 48,744	$ 45,782
Special deposits	17,804	103,789
Investments in securitizable assets	272,131	252,801
Receivables, less provision for uncollectible accounts of $25,879 in 2006 and $24,444 in 2005	439,730	901,516
Unbilled revenues	78,916	175,853
Taxes receivable	125,665	-
Fuel, materials and supplies	159,120	206,557
Marketable securities - current	61,769	56,012
Derivative assets - current	168,778	403,507
Prepayments and other	92,861	129,242
Assets held for sale	856,925	101,784
	2,322,443	2,376,843
Property, Plant and Equipment:		
Electric utility	6,679,131	6,378,838
Gas utility	842,800	825,872
Competitive energy	21,373	908,776
Other	274,163	254,659
	7,817,467	8,368,145
Less: Accumulated depreciation	2,552,349	2,551,322
	5,265,118	5,816,823
Construction work in progress	621,906	600,407
	5,887,024	6,417,230

Deferred Debits and Other Assets:		
Regulatory assets	2,102,778	2,483,851
Goodwill	287,591	287,591
Prepaid pension	274,501	298,545
Marketable securities - long-term	49,632	56,527
Derivative assets - long-term	320,228	425,049
Other	214,755	223,439
	3,249,485	3,775,002
Total Assets	$ 11,458,952	$ 12,569,075

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED
BALANCE SHEETS
(Unaudited)

	June 30, 2006	December 31, 2005
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 131,000	$ 32,000
Long-term debt - current portion	26,731	22,673
Accounts payable	563,332	972,368
Accrued taxes	-	95,210
Accrued interest	41,829	47,742
Derivative liabilities - current	187,030	402,530
Counterparty deposits	6,663	28,944
Other	302,430	272,252
Liabilities of assets held for sale	356,466	101,511
	1,615,481	1,975,230
Rate Reduction Bonds	1,247,175	1,350,502
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,400,547	1,306,340
Accumulated deferred investment tax credits	93,608	95,444
Deferred contractual obligations	300,951	358,174
Regulatory liabilities	844,289	1,273,501
Derivative liabilities - long-term	185,482	272,995
Other	356,331	364,157
	3,181,208	3,670,611
Capitalization:		
Long-Term Debt	2,945,024	3,027,288

Preferred Stock of Subsidiary - Non-Redeemable		116,200		116,200
Common Shareholders' Equity:				
Common shares, $5 par value - authorized 225,000,000 shares; 175,126,947 shares issued and 153,714,955 shares outstanding in 2006 and 174,897,704 shares issued and 153,225,892 shares outstanding in 2005		875,635		874,489
Capital surplus, paid in		1,441,298		1,437,561
Deferred contribution plan - employee stock ownership plan		(40,162)		(46,884)
Retained earnings		433,273		504,301
Accumulated other comprehensive income		4,604		19,987
Treasury stock, 19,676,058 shares in 2006 and 19,645,511 shares in 2005		(360,784)		(360,210)
Common Shareholders' Equity		2,353,864		2,429,244
Total Capitalization		5,415,088		5,572,732
Commitments and Contingencies (Note 7)				
Total Liabilities and Capitalization	$	11,458,952	$	12,569,075

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/(LOSS)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 1,670,531	$ 1,531,613	$ 3,817,919	$ 3,764,577
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	1,106,280	979,925	2,643,480	2,649,087
Other	266,701	272,390	575,472	517,489
Wholesale contract market changes, net	12,861	69,574	19,691	258,466
Restructuring and impairment charges	3,282	2,120	8,425	23,654
Maintenance	49,200	50,219	87,621	86,522
Depreciation	59,589	55,124	118,355	110,258
Amortization	(1,078)	24,026	57,394	47,119
Amortization of rate reduction bonds	43,997	41,116	92,675	86,906
Taxes other than income taxes	54,442	53,210	130,867	127,404
Total operating expenses	1,595,274	1,547,704	3,733,980	3,906,905
Operating Income/(Loss)	75,257	(16,091)	83,939	(142,328)
Interest Expense:				
Interest on long-term debt	36,716	32,833	72,527	63,056
Interest on rate reduction bonds	18,982	22,235	38,863	45,273
Other interest	7,626	8,230	13,626	11,314

Interest expense, net	63,324	63,298	125,016	119,643
Other Income, Net	12,676	10,288	28,096	16,194
Income/(Loss) from Continuing Operations Before				
Income Tax Expense/(Benefit)	24,609	(69,101)	(12,981)	(245,777)
Income Tax Expense/(Benefit)	8,920	(32,104)	(9,385)	(96,873)
Income/(Loss) from Continuing Operations Before				
Preferred Dividends of Subsidiary	15,689	(36,997)	(3,596)	(148,904)
Preferred Dividends of Subsidiary	1,389	1,389	2,779	2,779
Income/(Loss) from Continuing Operations	14,300	(38,386)	(6,375)	(151,683)
Discontinued Operations:				
Income from Discontinued Operations,				
Before Income Taxes	20,364	18,469	38,847	11,464
Loss from Sale of Discontinued Operations	(5,578)	-	(6,478)	-
Income Tax Expense	6,844	7,787	13,858	5,204
Income from Discontinued Operations	7,942	10,682	18,511	6,260
Net Income/(Loss)	$ 22,242	$ (27,704)	$ 12,136	$ (145,423)
Basic and Fully Diluted Earnings/(Loss) Per Common Share:				
Income/(Loss) from Continuing Operations	$ 0.09	$ (0.30)	$ (0.04)	$ (1.17)
Income from Discontinued Operations	0.05	0.09	0.12	0.05
Basic and Fully Diluted Earnings/(Loss) Per Common Share	$ 0.14	$ (0.21)	$ 0.08	$ (1.12)
Basic Common Shares Outstanding (average)	153,628,709	129,520,644	153,535,675	129,399,574
	153,922,635	129,520,644	153,809,133	129,399,574

Fully Diluted Common
Shares Outstanding
(average)

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, 2006	Six Months Ended June 30, 2005
	(Thousands of Dollars)	
Operating Activities:		
Net income/(loss)	$ 12,136	$ (145,423)
Adjustments to reconcile to net cash flows provided by operating activities:		
Wholesale contract market changes, net	19,691	203,572
Restructuring and impairment charges	6,715	47,812
Bad debt expense	21,181	15,229
Depreciation	121,445	116,349
Deferred income taxes	168,525	(92,457)
Amortization	57,394	47,119
Amortization of rate reduction bonds	92,675	86,906
(Deferral)/amortization of recoverable energy costs	(7,616)	31,544
Pension expense	18,454	16,465
Regulatory refunds	(141,968)	(59,929)
Derivative assets and liabilities	(76,793)	13,158
Deferred contractual obligations	(50,282)	(43,407)
Other non-cash adjustments	(20,545)	34,804
Other sources of cash	22,147	4,148
Other uses of cash	(5,548)	(31,530)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	543,368	85,656
Fuel, materials and supplies	33,108	8,141
Investments in securitizable assets	(19,330)	(108,491)
Other current assets	11,664	(18,522)
Accounts payable	(408,632)	(11,856)

Counterparty deposits and margin special deposits	63,299	80,468
(Taxes receivable)/accrued taxes	(220,875)	25,886
Other current liabilities	(27,066)	(27,243)
Net cash flows provided by operating activities	213,147	278,399
Investing Activities:		
Investments in property and plant:		
Electric, gas and other utility plant	(370,652)	(327,081)
Competitive energy assets	(10,051)	(4,989)
Cash flows used for investments in property and plant	(380,703)	(332,070)
Net proceeds from sale of property	150	23,792
Cash payment for sale of competitive businesses	(19,429)	-
Proceeds from sales of investment securities	84,695	54,532
Purchases of investment securities	(79,903)	(56,003)
Other investing activities	(1,139)	5,543
Net cash flows used in investing activities	(396,329)	(304,206)
Financing Activities:		
Issuance of common shares	4,068	7,565
Issuance of long-term debt	250,000	200,000
Retirement of rate reduction bonds	(103,327)	(96,729)
Increase/(decrease) in short-term debt	99,000	(2,844)
Reacquisitions and retirements of long-term debt	(10,631)	(48,459)
Cash dividends on common shares	(54,025)	(41,629)
Other financing activities	1,059	16,397
Net cash flows provided by financing activities	186,144	34,301
Net increase in cash and cash equivalents	2,962	8,494
Cash and cash equivalents - beginning of period	45,782	46,989
Cash and cash equivalents - end of period	$ 48,744	$ 55,483

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 complete report on Form 10-Q, the first quarter 2006 Form 10-Q, and the Annual Reports of Northeast Utilities (NU or the company), The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), and Western Massachusetts Electric Company (WMECO), which were filed as part of the Northeast Utilities and subsidiaries combined 2005 Form 10-K (NU 2005 Form 10-K) with the SEC, and the current report on Form 8-K dated June 7, 2006 that updated the 2005 Form 10-K to present certain portions of the business as discontinued operations for all periods. 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, 2006, and the results of operations for the three and six months ended June 30, 2006 and 2005 and cash flows for the six months ended June 30, 2006 and 2005. The results of operations and statements of cash flows for the six months ended June 30, 2006 and 2005 are not necessarily indicative of the results expected for a full year.

The condensed consolidated financial statements of NU and of 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.

In NU s condensed consolidated statements of income/(loss) and CL&P's, PSNH's and WMECO's condensed consolidated statements of income, the classification of expense amounts relating to compensation costs not recoverable from regulated customers, advertising costs, environmental charges and rate reduction bond service fees previously included in other income, net was changed to a more preferable presentation. These expense amounts, which were reclassified to other operation expense for NU, CL&P, PSNH, and WMECO, totaled $3.7 million, $1.9 million, $1 million and $0.2 million, respectively, for the three months ended June 30, 2005. Similar amounts for the six months ended June 30, 2005 for NU, CL&P, PSNH, and WMECO totaled $9.1 million, $2.9 million, $1.9 million and $0.4 million, respectively. These reclassifications had no impact on the companies' results of operations, cash flows, financial condition or changes in shareholders' equity.

NU s condensed consolidated statements of income/(loss) for all periods presented classify the operations for the following as discontinued operations, which were reflected in the report on Form 8-K dated June 7, 2006:

- Northeast Generation Company (NGC),
- The Mt. Tom generating plant (Mt. Tom) 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,
- Woods Electrical Co., Inc. (Woods Electrical),
-

Select Energy Contracting, Inc. - New Hampshire (SECI-NH) (including Reeds Ferry Supply Co., Inc. (Reeds Ferry)), a division of Select Energy Contracting, Inc. (SECI), and

•

Woods Network Services, Inc. (Woods Network).

At June 30, 2006, all assets and liabilities of NGC and Mt. Tom have been classified as assets held for sale and liabilities of assets held for sale on the accompanying condensed consolidated balance sheet. At December 31, 2005, assets held for sale and liabilities of assets held for sale consisted of certain assets and liabilities of SESI and Woods Electrical. For further information regarding these companies, see Note 4, "Assets Held for Sale and Discontinued Operations."

B.

Accounting Standards Issued But Not Yet Adopted

Accounting for Servicing of Financial Assets: In March of 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 156, "Accounting for Servicing of Financial Assets - An Amendment of FASB Statement No. 140." SFAS No. 156 requires an entity to recognize a servicing asset or liability at fair value each time it undertakes an obligation to service a financial asset by entering into a servicing contract in a transfer of the servicer's financial assets that meets the requirements for sale accounting and in other circumstances. Servicing assets and liabilities may be subsequently measured through either amortization or recognition of fair value changes in earnings. SFAS No. 156 is required to be applied prospectively to transactions beginning in the first quarter of 2007 and may affect the accounting treatment of CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. Implementation of this statement is not expected to have a material effect on the company's financial statements.

Uncertain Tax Positions: On July 13, 2006, the FASB issued FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109." FIN 48 addresses the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. FIN 48 is required to be implemented in the first quarter of 2007 prospectively as a change in accounting principle with a cumulative effect adjustment reflected in the opening balance of retained earnings. The company is currently evaluating the potential impacts of FIN 48 on its financial statements.

C.

Regulatory Accounting

The accounting policies of the Utility Group 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 businesses of CL&P, PSNH and WMECO, along with PSNH's generation business and Yankee Gas Services Company's (Yankee Gas) distribution business, continue to be cost-of-service rate regulated, and management believes that the application of SFAS No. 71 to those businesses continues to be appropriate. Management also believes that it is probable that the Utility Group will recover its investments in long-lived assets, including regulatory assets. In addition, all material net regulatory assets are earning an equity return, except for securitized regulatory assets, which are not supported by equity, and substantial portions of the unrecovered contractual obligations regulatory assets. Amortization and deferrals of regulatory assets are included on a net basis in amortization expense on the accompanying condensed consolidated statements of income/(loss).

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

	At June 30, 2006				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas**
Recoverable nuclear costs	$ 15.8	$ -	$ -	$ 15.8	$ -
Securitized assets	1,237.6	782.5	350.8	104.3	-
Income taxes, net	308.8	229.9	13.6	48.1	17.2
Unrecovered contractual obligations	226.6	170.6	-	56.0	-
Recoverable energy costs	40.3	38.1	-	2.2	-
CTA undercollections	73.0	73.0	-	-	-
Other regulatory assets/(overrecoveries)	200.7	73.5	64.4	4.8	58.0
Totals	$2,102.8	$1,367.6	$428.8	$231.2	$75.2

	At December 31, 2005				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas**
Recoverable nuclear costs	$ 44.1	$ -	$ 26.1	$ 18.0	$ -
Securitized assets	1,340.9	855.6	375.0	110.3	-
Income taxes, net	332.5	227.6	35.9	51.6	17.4
Unrecovered contractual obligations	327.5	197.7	63.2	66.6	-
Recoverable energy costs	193.0	7.3	171.5	2.5	11.7
Other regulatory assets/(overrecoveries)	245.9	69.8	150.3	(25.8)	51.6
Totals	$2,483.9	$1,358.0	$822.0	$223.2	$80.7

At June 30, 2006, CL&P's CTA was recorded as a $73 million regulatory asset as CTA unrecovered costs were in excess of CTA collections due to refunds to customers. At December 31, 2005, CTA collections were in excess of CTA costs and a $26 million regulatory liability was recorded.

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Included in NU's other regulatory assets/(overrecoveries) above are regulatory assets associated with the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $50.8 million at June 30, 2006 and $47.3 million at December 31, 2005. A portion of these ARO regulatory assets totaling $17.7 million at June 30, 2006 and $17.3 million at December 31, 2005 has been approved for deferred accounting treatment. At this time, management believes that the remaining regulatory assets are also probable of recovery.

The restructuring settlement agreement between PSNH and the state of New Hampshire, which was implemented in May of 2001, requires that non-securitized stranded costs be recovered from PSNH's customers prior to a recovery end date of October 31, 2007. On June 30, 2006, under the terms of the restructuring settlement agreement, PSNH completed the recovery of its non-securitized stranded costs and offset the remaining stranded cost regulatory asset balances totaling $345.8 million against an offsetting regulatory liability for the cumulative deferral of Stranded Cost Recovery Charge (SCRC) revenues. As of June 30, 2006 PSNH had $2.4 million of accumulated SCRC costs remaining for recovery. The SCRC costs will be recovered from customers over the six month period beginning in July of 2006 through December of 2006 in the SCRC rate.

Included in WMECO's other regulatory assets/(overrecoveries) are $25.4 million and $37.8 million at June 30, 2006 and December 31, 2005, respectively, of amounts related to WMECO's rate cap deferral. The rate cap deferral allows WMECO to recover stranded costs, and these amounts represent the cumulative excess of transition cost revenues over transition cost expenses.

Additionally, the Utility Group had $12.3 million and $11.2 million of regulatory costs at June 30, 2006 and December 31, 2005, respectively, that are included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets. These amounts represent regulatory costs that have not yet been approved by the applicable regulatory agency. Management believes these assets are recoverable in future cost of service regulated rates.

As discussed in Note 7D, "Commitments and Contingencies - Deferred Contractual Obligations," substantial portions of the unrecovered contractual obligations regulatory assets have not yet been approved for recovery. At this time management believes that these regulatory assets are probable of recovery.

Regulatory Liabilities: The Utility Group had $844.3 million of regulatory liabilities at June 30, 2006 and $1.3 billion at December 31, 2005, including revenues subject to refund. These amounts are comprised of the following:

	At June 30, 2006				
(Millions of Dollars)	NU Consolidated	CL&P	PSNH	WMECO	Yankee Gas
Cost of removal	$302.9	$138.3	$ 85.4	$23.7	$55.5
CL&P GSC and SBC overcollections	58.6	58.6	-	-	-
Regulatory liabilities offsetting Utility Group derivative assets	325.2	325.2	-	-	-
Other regulatory liabilities	157.6	72.9	46.3	0.5	37.9
Totals	$844.3	$595.0	$131.7	$24.2	$93.4

	At December 31, 2005				
(Millions of Dollars)	NU Consolidated	CL&P	PSNH	WMECO	Yankee Gas
Cost of removal	$ 305.5	$139.4	$ 85.7	$23.6	$56.8
CL&P CTA, GSC and SBC overcollections	154.0	154.0	-	-	-
PSNH cumulative deferral - SCRC	303.3	-	303.3	-	-
Regulatory liabilities offsetting Utility Group derivative assets	391.2	391.2	-	-	-
Other regulatory liabilities	119.5	58.4	25.6	0.2	35.3
Totals	$1,273.5	$743.0	$414.6	$23.8	$92.1

For information regarding derivative assets, see Note 5, "Derivative Instruments."

D.

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) is a non-cash item that is included in the cost of Utility Group 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 in other interest expense, and the cost of equity funds is recorded as other income on the condensed consolidated statements of income/(loss), as follows:

	For the Three Months Ended		For the Six Months Ended	
(Millions of Dollars)	June 30, 2006	June 30, 2005	June 30, 2006	June 30, 2005
Borrowed funds	$3.2	$2.4	$6.1	$4.2
Equity funds	2.6	2.4	6.3	4.2
Totals	$5.8	$4.8	$12.4	$8.4
Average AFUDC rates	6.7%	5.2%	6.6%	4.9%

The average Utility Group 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 amounts to calculate AFUDC. Fifty percent of construction work in progress of CL&P's four major transmission projects in southwest Connecticut is recovered currently in rates. The remaining fifty percent earns AFUDC. The increase in AFUDC from borrowed funds during the three months ended June 30, 2006 as compared to the three months ended June 30, 2005 results from CL&P s issuance of additional debt in June of 2006. The increase in the average AFUDC rate in 2006 is primarily due to lower levels of short-term debt outstanding and higher equity levels in 2006 as compared to 2005.

E.

Share-Based Payments

NU maintains an Employee Stock Purchase Plan (ESPP) and other long-term equity-based incentive plans under the Northeast Utilities Incentive Plan (Incentive Plan). In the first quarter of 2006, NU adopted SFAS No. 123(R), "Share-Based Payments," under the modified prospective method. Adoption of SFAS No. 123(R) had a de minimus effect on NU s net income/(loss) and no effect on NU s income/(loss) per share. For the six months ended June 30, 2006, a tax benefit in excess of compensation cost totaling $0.2 million increased cash flows from financing activities.

SFAS No. 123(R) requires that share-based payments be recorded using the fair value-based method based on the fair value at the date of grant and applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed. For prior periods, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," and related guidance, NU used the intrinsic value method and disclosed the pro forma effects as if NU recorded equity-based compensation under the fair value-based method.

NU accounts for its various share-based plans as follows:

- For grants of restricted stock and restricted stock units (RSUs), NU continues to record compensation expense over the vesting period based upon the fair value of NU's common stock at the date of grant, but records this expense net of estimated forfeitures. Previously, forfeitures were recorded as they occurred. Dividend equivalents on RSUs, previously included in compensation expense, are charged to retained earnings net of estimated forfeitures.

- For shares granted under the Employee Stock Purchase Plan (ESPP), an immaterial amount of compensation expense was recorded in the first quarter of 2006, and no future compensation expense was recorded in the second quarter of 2006 or will be recorded in future periods as a result of a plan amendment that was effective on February 1, 2006.

- NU has not granted any stock options since 2002, and no compensation expense has been recorded. All options were fully vested prior to January 1, 2006.

Incentive Plans: Under the Incentive Plan, NU is authorized to grant new shares for various types of awards, including restricted shares, restricted share units, performance units, and stock options to eligible employees and board members. The number of shares that may be utilized for grants and awards during a given calendar year may not exceed the aggregate of one percent of the total number of NU common shares outstanding as of the first day of that calendar year plus the shares not utilized in previous years.

Restricted Shares and Restricted Share Units: NU has granted restricted shares under the 2004, 2003 and 2002 incentive programs that are subject to three-year and four-year graded vesting schedules. NU has granted RSUs under the 2004, 2005 and 2006 incentive programs that are subject to three-year and four-year graded vesting schedules. RSUs are paid in shares plus cash sufficient to satisfy withholdings subsequent to vesting. A summary of restricted shares and RSUs for the six months ended June 30, 2006 is as follows:

Restricted Shares	Restricted Shares	Weighted Average Grant - Date Fair Value	Total Weighted Average Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2005	152,901	N/A			
Granted	-	-			
Vested	(74,243)	$14.52	$1.1		
Forfeited	(1,388)	$14.17			
Outstanding at March 31, 2006	77,270	$14.87	$1.1	$1.0	1.0
Granted	-	-	-		
Vested	-	-	-		
Forfeited	(3,405)	$14.14			
Outstanding at June 30, 2006	73,865	$14.90	$1.1	$0.7	0.8

The weighted average grant date fair value per share for restricted shares vested was $14.60 for the six months ended June 30, 2005. The total weighted average fair value of restricted shares vested was $1.4 million during the six months ended June 30, 2005. No shares were vested during the three months ended June 30, 2006 or 2005.

The total compensation cost recognized during the three and six months ended June 30, 2006 was $0.1 million and $0.3 million, net of taxes of approximately $0.1 million and $0.2 million, respectively. The total compensation cost recognized during the three and six months ended June 30, 2005 was $0.2 million and $0.4 million, net of taxes of approximately $0.1 million and $0.2 million, respectively.

RSUs	RSUs (Units)	Weighted Average Grant - Date Fair Value	Total Weighted Average Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2005	521,273	N/A			

Granted	352,783	$19.66			
Paid	(109,579)	$18.43	$ 2.0		
Forfeited	(5,604)	$18.93			
Outstanding at March 31, 2006	758,873	$19.27	$14.6	$11.6	2.4
Granted	6,244	$20.67	-		
Paid	(2,516)	$19.11	-		
Forfeited	(18,870)	$19.19			
Outstanding at June 30, 2006	743,731	$19.40	$14.4	$10.0	2.1

The weighted average grant date fair value per share for RSUs granted during the three and six months ended June 30, 2005 was $20.86 and $18.79, respectively. The weighted average grant date fair value per share for RSUs paid during the three and six months ended June 30, 2005 was $18.90 and $19.06, respectively. The total weighted average fair value of RSUs paid during the three and six months ended June 30, 2005 was approximately $4 thousand and $1.8 million, respectively.

The total compensation cost recognized for the three and six months ended June 30, 2006 was $0.8 million and $1.4 million, respectively, net of taxes of approximately $0.5 million and $0.9 million, respectively. The total compensation cost recognized during the three and six months ended June 30, 2005 was $0.8 million and $1 million, net of taxes of approximately $0.6 million and $0.7 million, respectively.

Stock Options: Prior to 2003, NU granted stock options to certain employees. These options were fully vested as of January 1, 2006. The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average remaining contractual lives for the options outstanding at June 30, 2006 is 4.4 years.

A summary of stock option transactions is as follows:

		Exercise Price Per Share			
	Options	**Range**			**Weighted Average**
Outstanding - December 31, 2005	**1,122,541**	**$14.9375**	-	**$22.2500**	**$18.4484**
Exercised	8,166	$16.3100	-	$19.5000	$17.7861
Forfeited and cancelled	18,750	$21.0300	-	$21.0300	$21.0300
Outstanding and Exercisable - March 31, 2006	**1,095,625**	**$14.9375**	-	**$22.2500**	**$18.4091**
Exercised	51,817	$14.9375	-	$19.5000	$17.9485
Forfeited and cancelled	-	N/A	-	N/A	$ -
Outstanding and Exercisable - June 30, 2006	**1,043,808**	**$14.9375**	-	**$22.2500**	**$18.4320**

Cash received for options exercised during the three and six months ended June 30, 2006 totaled $0.9 million and $1 million, respectively.

Employee Share Purchase Plan (ESPP): NU maintains an ESPP for all eligible employees. Prior to February 1, 2006, NU common shares were purchased by employees at six-month intervals at 85 percent of the lower of the price on the first or last day of each six-month period. Employees were permitted to purchase shares having a value not exceeding 25 percent of their compensation as of the beginning of the purchase period. Effective February 1, 2006, the ESPP was amended to change the discount rate to five percent of the market price on the last day of the purchase period. As a result, the ESPP qualifies as a non-compensatory plan under SFAS No. 123(R).

The following table illustrates the pro forma effect if NU had applied the recognition provisions of SFAS No. 123 to share-based compensation:

(Millions of Dollars, except per share amounts)	**For the Three Months Ended June 30, 2005**	**For the Six Months Ended June 30, 2005**
Net loss, as reported	$(27.7)	$(145.4)
Add: Share-based payments included in reported net loss, net of related tax effects	1.0	1.4

Net loss before share-based payments	(26.7)	(144.0)
Deduct: Total share-based payments determined under the fair value-based method for all awards, net of related tax effects	(1.2)	(1.8)
Pro forma net loss	$(27.9)	$(145.8)
Loss Per Share:		
Basic and fully diluted - as reported	$(0.21)	$ (1.12)
Basic and fully diluted - pro forma	$(0.21)	$ (1.12)

An income tax rate of 40 percent is used to estimate the tax effect on total share-based payments determined under the fair value-based method for all awards.

F.

Sale of Customer Receivables

At June 30, 2006 and December 31, 2005, CL&P had sold an undivided interest in its accounts receivable of $100 million and $80 million, respectively, to a financial institution with limited recourse through CRC. CRC can sell up to $100 million of an undivided interest in its accounts receivable and unbilled revenues. At June 30, 2006 and December 31, 2005, the reserve requirements calculated in accordance with the Receivables Purchase and Sale Agreement were $17.8 million and $21 million, respectively. These reserve amounts are deducted from the amount of receivables eligible for sale. At their present levels, these reserve amounts do not limit CL&P s ability to access the full amount of the facility. Concentrations of credit risk to the purchaser under this agreement with respect to the receivables are limited due to CL&P s diverse customer base.

At June 30, 2006 and December 31, 2005, amounts sold to CRC by CL&P but not sold to the financial institution totaling $272.1 million and $252.8 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 5, 2006, CRC renewed the bank commitment for the Receivables Purchase and Sale Agreement with CL&P and the financial institution through July 3, 2007 to coincide with the date this agreement terminates, unless otherwise extended. 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."

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In addition, the company is in the process of evaluating the effect of SFAS No. 156 on its accounting for the sale of these receivables. See Note 1B, "Accounting Standards Issued But Not Yet Adopted," for further information.

G.

Investment in CYAPC

The operating subsidiaries of NU collectively own 49 percent of the common stock of Connecticut Yankee Atomic Power Company (CYAPC) with a carrying value of $23.4 million at June 30, 2006. This amount is included in deferred debits and other assets other on the accompanying condensed consolidated balance sheets. CYAPC filed with the FERC to recover the increased estimate of decommissioning and plant closure costs. This FERC proceeding is ongoing. Parties to these proceedings are currently engaged in settlement discussions, the outcome of which management cannot determine at this time. Management believes that the FERC proceeding has not impaired the value of its investment in CYAPC at June 30, 2006 but will continue to evaluate the impacts, if any, that the FERC proceeding has on this investment. For further information, see Note 7D, "Commitments and Contingencies - Deferred Contractual Obligations," and Note 1K, "Other Income, Net."

H.

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.

I.

Special Deposits

Special deposits represent amounts Select Energy, Inc. (Select Energy) has on deposit with unaffiliated counterparties and brokerage firms in the amounts of $17.8 million and $103.8 million at June 30, 2006 and December 31, 2005, respectively. SESI special deposits totaling $10.2 million at December 31, 2005 are included in assets held for sale on the accompanying condensed consolidated balance sheets. SESI was sold in the second quarter of 2006.

J.

Counterparty Deposits

Balances collected from counterparties resulting from Select Energy s credit management activities totaled $6.7 million at June 30, 2006 and $28.9 million at December 31, 2005. These amounts are recorded as current liabilities and included as counterparty deposits on the accompanying condensed consolidated balance sheets. To the extent Select Energy requires collateral from counterparties, cash is received as a part of the total collateral required. The right to use such cash collateral in an unrestricted manner is determined by the terms of Select Energy s 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.

K.

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, 2006**	**June 30, 2005**	**June 30, 2006**	**June 30, 2005**
Other Income:				
Investment income	$ 3.5	$ 5.3	$12.6	$ 8.8
CL&P procurement fee	2.6	2.8	5.5	5.8
AFUDC - equity funds	2.6	2.4	6.3	4.2
Gain on sale of investment in Globix	3.1	-	3.1	-
Energy Independence Act incentives	2.5	-	2.5	-
Other	2.4	3.8	4.3	6.0
Total Other Income	$16.7	$14.3	$34.3	$24.8
Other Loss:				
Charitable donations	$ 0.7	$ 0.9	$ 1.4	$ 1.7
Lobbying costs	1.8	0.8	2.6	2.0
Loss on investments in securitizable assets	0.7	0.4	1.1	0.8
Loss on disposition of property	-	0.8	-	0.9
Other	0.8	1.1	1.1	3.2
Total Other Loss	$ 4.0	$ 4.0	$ 6.2	$ 8.6
Total Other Income, Net	$12.7	$10.3	$28.1	$16.2

CL&P (Millions of Dollars)	For the Three Months Ended June 30, 2006	June 30, 2005	For the Six Months Ended June 30, 2006	June 30, 2005
Other Income:				
Investment income	$ 1.9	$2.6	$ 7.7	$ 4.9
CL&P procurement fee	2.6	2.8	5.5	5.8
AFUDC - equity funds	1.0	2.0	3.5	3.6
Energy Independence Act incentives	2.5	-	2.5	-
Other	1.1	1.0	2.4	2.2
Total Other Income	$ 9.1	$8.4	$21.6	$16.5
Other Loss:				
Charitable donations	$ 0.5	$0.4	$ 0.8	$ 1.0
Lobbying costs	1.3	0.4	1.7	1.1
Loss on investments in securitizable assets	0.7	0.4	1.1	0.8
Other	0.4	0.3	0.6	1.5
Total Other Loss	$ 2.9	$1.5	$ 4.2	$ 4.4
Total Other Income, Net	$ 6.2	$6.9	$17.4	$12.1

PSNH (Millions of Dollars)	For the Three Months Ended June 30, 2006	June 30, 2005	For the Six Months Ended June 30, 2006	June 30, 2005
Other Income:				
Investment income	$0.5	$0.2	$0.8	$0.4
AFUDC - equity funds	0.9	0.2	2.0	0.5
Conservation and load management incentive	-	0.5	-	0.6
Other	0.1	0.6	0.1	0.5
Total Other Income	$1.5	$1.5	$2.9	$2.0
Other Loss:				
Charitable donations	$0.1	$0.2	$0.4	$0.4
Lobbying costs	0.2	0.2	0.4	0.4
Other	0.1	0.2	0.1	0.2
Total Other Loss	$0.4	$0.6	$0.9	$1.0
Total Other Income, Net	$1.1	$0.9	$2.0	$1.0

WMECO	**For the Three Months Ended**		**For the Six Months Ended**	
(Millions of Dollars)	**June 30, 2006**	**June 30, 2005**	**June 30, 2006**	**June 30, 2005**
Other Income:				
Investment income/(loss)	$(0.3)	$0.2	$ -	$0.2
Gain on disposition of property	0.2	-	0.2	0.1
Conservation and load management incentive	0.2	0.2	0.6	0.2
Millstone 1 recovery amortization	0.2	0.2	0.5	0.5
Other	-	0.1	0.2	0.1
Total Other Income	$0.3	$0.7	$1.5	$1.1
Other Loss:				
Charitable donations	$ -	$0.2	$0.1	$0.2
Lobbying costs	0.1	0.1	0.3	0.3
Other	-	0.1	0.1	0.1
Total Other Loss	$0.1	$0.4	$0.5	$0.6
Total Other Income, Net	$0.2	$0.3	$1.0	$0.5

Investment income for NU includes equity in earnings/(losses) of regional nuclear generating and transmission companies of $(2.2) million and $1 million for the three months ended June 30, 2006 and 2005, respectively, and $(1.2) million and $1.9 million for the six months ended June 30, 2006 and 2005, respectively. Equity in earnings relates to NU s investment in CYAPC, Maine Yankee Atomic Power Company (MYAPC), and Yankee Atomic Electric Company (YAEC) (Yankee companies) 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. 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.

None of the amounts in either other income - other or other loss - other are individually significant.

L.

Asset Retirement Obligations

The Department of Public Utility Control (DPUC) initiated a proceeding relating to an incident involving the failure of certain porcelain cutouts that are used in CL&P's distribution system. A cutout is a protective device that stops the flow of electricity if there is a surge. On April 26, 2006, the DPUC issued an order requiring CL&P to report its progress in replacing porcelain cutouts. As a result of a requirement to remove the porcelain cutouts, an asset retirement obligation (ARO) has been recorded. At June 30, 2006, the fair value of the ARO asset recorded is $4.7 million, accumulated depreciation is $0.6 million, and the ARO liability is $4.7 million. The charge to record the $0.6 million of accumulated depreciation was recorded as a regulatory asset, as management believes that this amount is recoverable in rates. Removal of these assets is expected to occur over three years beginning in 2006.

2.

WHOLESALE CONTRACT MARKET CHANGES (NU, NU Enterprises)

NU recorded $12.9 million and $69.6 million of pre-tax wholesale contract market changes for the three months ended June 30, 2006 and 2005, respectively, and $19.7 million and $258.5 million for the six months ended June 30, 2006 and 2005, respectively, related to the changes in the fair value of wholesale contracts. These changes are comprised of the following items:

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Charges of $11.9 million and $18.7 million for the three and six months ended June 30, 2006 and $64.2 million and $358.5 million for the three and six months ended June 30, 2005, respectively, associated with the mark-to-market on certain long-dated wholesale electricity contracts in New England, New York and PJM and contracts to purchase generation products in New England and New York. The decision in March of 2005 to exit the wholesale marketing business changed management s conclusion regarding the likelihood that these wholesale marketing contracts would result in physical delivery to customers. This in turn resulted in a change in the first quarter of 2005 from accrual accounting to mark-to-market accounting for the wholesale marketing contracts.

- A charge of $1 million in the second quarter and first half of 2006 related to the mark-to-market of certain asset specific sales and forward sales of electricity at hub points for generation contracts.

- A positive mark-to-market of $100 million in the first half of 2005. This includes a benefit of $94 million for the three months ended March 31, 2005 for mark-to-market gains primarily related to retail supply contracts by the wholesale business that were previously used to serve retail electric load and a benefit of $20.4 million for other wholesale contracts related to electricity that would have been delivered to customers primarily in 2005 and 2006. The positive mark-to-market is offset by a charge of $14.4 million for mark-to-market contract asset write-offs and a contract termination payment in March of 2005.

- A charge of $5.4 million in the second quarter of 2005 related to a decrease in the mark-to-market on certain retail marketing supply contracts and other wholesale contracts (included in the first half benefit of $20.4 million above) related to electricity for delivery to customers primarily in 2005 and 2006.

Included in the mark-to-market on long-term wholesale electricity contracts is a $15.7 million and $70.2 million pre-tax mark-to-market charge for the three and six months ended June 30, 2005, respectively, related to an intercompany contract between Select Energy and CL&P. This contract was included in the portfolio of contracts Select Energy assigned to a third party wholesale power marketer, and Select Energy stopped serving CL&P on December 31, 2005. This contract was part of CL&P s stranded costs, and benefits received by CL&P under this contract were provided to CL&P s ratepayers in the form of lower than market standard offer service rates. A $2.8 million pre-tax mark-to-market charge in the first half of 2005 was recorded as wholesale contract market changes by Select Energy for the intercompany contract between Select Energy and WMECO for default service from April to June of 2005. There were no wholesale contract market changes in the second quarter of 2005 as this contract expired on June 30, 2005. WMECO s benefits under this contract were provided to its ratepayers in the form of lower than market default service rates. These charges were not eliminated in consolidation because on a consolidated basis NU retained the over-market obligation to its ratepayers of CL&P and WMECO.

For further information regarding derivative assets and liabilities, see Note 5, "Derivative Instruments."

3.

RESTRUCTURING AND IMPAIRMENT CHARGES (NU, NU Enterprises)

The company evaluates long-lived assets such as property, plant and equipment to determine if these assets are impaired when events or changes in circumstances occur such as the 2005 announced decisions to exit all of the NU Enterprises businesses.

When the company believes one of these events has occurred, a determination needs to be made if a long-lived asset should be classified as an asset to be held and used or if that asset should be classified as held for sale. For assets classified as held and used, the company estimates the undiscounted future cash flows associated with the long-lived asset or asset group and an impairment loss is recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. For assets held for sale, a long-lived asset or disposal group is measured at the lower of its carrying amount or fair value less cost to sell.

NU Enterprises recorded $9.5 million and $2.3 million of pre-tax restructuring and impairment charges for the three months ended June 30, 2006 and 2005, respectively, and $15.6 million and $47.8 million for the six months ended June 30, 2006 and 2005, respectively, related to exiting the merchant energy businesses and its energy services businesses. The amounts related to continuing operations are included as restructuring and impairment charges on the condensed consolidated statements of income/(loss) with the remainder included in discontinued operations. These charges are included as part of the NU Enterprises reportable segment in Note 12, "Segment Information." A summary of these pre-tax charges is as follows:

	For the Three Months Ended		**For the Six Months Ended**	
(Millions of Dollars)	**June 30, 2006**	**June 30, 2005**	**June 30, 2006**	**June 30, 2005**
Merchant Energy:				
Wholesale Marketing:				
Restructuring charges	$0.6	$ 1.0	$ 0.6	$ 1.0
Retail Marketing:				
Impairment charges	$ -	$ -	$ -	$ 7.2
Restructuring charges	0.8	-	5.5	-
Subtotal	$0.8	$ -	$ 5.5	$ 7.2
Competitive Generation:				
Impairment charges	$ 0.3	$ -	$ 0.3	$ -

Restructuring charges	0.9	-	2.6	-
Subtotal	$1.2	$ -	$ 2.9	$ -
Subtotal - Merchant Energy	$2.6	$1.0	$ 9.0	$ 8.2
Energy Services and Other:				
Impairment charges	$0.1	$0.8	$ 0.1	$39.1
Restructuring charges	6.8	0.5	6.5	0.5
Subtotal - Energy Services and Other	$6.9	$1.3	$ 6.6	$39.6
Total restructuring and impairment charges	$9.5	$2.3	$15.6	$47.8
Restructuring and impairment charges included in discontinued operations	$6.2	$0.2	$ 7.2	$24.1
Total restructuring and impairment charges included in continuing operations	$3.3	$2.1	$ 8.4	$23.7

For segment reporting purposes, $0.4 million and $0.4 million of wholesale marketing restructuring charges, $0.9 million and $2.6 million of Retail Marketing restructuring charges and $0.9 million and $2.6 million of Competitive Generation restructuring charges for the three and six months ended June 30, 2006, respectively, are included in the NU Enterprises - Services and Other reportable segment, as these amounts were recorded by NU Enterprises parent.

On May 5, 2006, NU Enterprises completed the sale of SESI to Ameresco, Inc. (Ameresco). In connection with the closing of this transaction, NU Enterprises paid Ameresco approximately $7.7 million and recorded a pre-tax restructuring charge of $5.6 million in the second quarter of 2006 in the Energy Services and Other segment, 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 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. Offsetting the first half loss is a restructuring benefit of $1.7 million for the gain on the sale of Massachusetts service location of Select Energy Contracting, Inc. - Connecticut (SECI-CT). 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.

On June 1, 2006, NU Enterprises completed the sale of SENY to Hess Corporation (Hess). In connection with the closing of this transaction, NU Enterprises recorded restructuring charges of $0.3 million to the Retail Marketing segment, which is included in restructuring and impairment charges on the accompanying condensed consolidated statements of income/(loss) 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 for consulting fees, legal fees, employee-related costs and other costs.

In the second quarter and first half of 2006, $0.3 million of impairments were recorded to the Competitive Generation segment related to certain long lived assets of Northeast Generation Services Company (NGS) that were no longer recoverable and 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.

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

In the first half of 2005, NU Enterprises hired an outside firm to assist in valuing its energy services business and their exit. Based in part on that firm s work, the company concluded that $29.1 million of goodwill associated with those businesses and $9.2 million of intangible assets were impaired as of March 31, 2005. In the second quarter of 2005, the energy services businesses and NU Enterprises parent recorded an additional impairment charge of $0.8 million due to the impairment of certain fixed assets resulting in a total impairment charge of $39.1 million for the first half of 2005 included in the Energy Services and Other segment.

Also in the first quarter of 2005, an exclusivity agreement intangible asset included in the Retail Marketing segment totaling $7.2 million was written off.

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, 2006 and December 31, 2005:

(Millions of Dollars)	**Employee - Related Costs**	**Professional Fees**	**Net (Gain)/ Loss on Sale**	**Total**
Restructuring liability as of January 1, 2005	$ -	$ -	$ -	$ -

Costs incurred	2.3	7.4	-	9.7
Cash payments	(0.5)	(2.1)	-	(2.6)
Restructuring liability as of December 31, 2005	1.8	5.3	-	7.1
Costs incurred/gain on sale	0.3	6.5	(0.7)	6.1
Cash payments	(0.3)	(4.6)	0.7	(4.2)
Restructuring liability as of March 31, 2006	1.8	7.2	-	9.0
Cost incurred/loss on sale	2.0	1.2	5.9	9.1
Cash payments and other deductions	(0.6)	(3.4)	(5.9)	(9.9)
Restructuring liability as of June 30, 2006	$ 3.2	$ 5.0	$ -	$ 8.2

In addition to the $0.6 million of retail marketing severance costs included in restructuring charges above, $3.7 million of other retail marketing severance costs and other employee benefits were recorded in other operating expenses on the accompanying condensed consolidated statements of income/(loss) for the six months ended June 30, 2006 because these amounts are for severance under an existing benefit arrangement. For further information, see Note 11, "Pension Benefits and Postretirement Benefits Other Than Pensions."

4.

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

A summary of the NU Enterprises businesses held for sale status as of June 30, 2006 and December 31, 2005, as well as the discontinued operations status for all periods presented including date sold, is as follows:

	Held for Sale Status as of			
	June 30, 2006	**December 31, 2005**	**Discontinued Operations**	**Sale Date**
Wholesale Marketing	No	No	No	N/A
Retail Marketing	Sold	No	No	June 2006
NGC (including certain components of NGS)	Yes	No	Yes	Expected by end of 2006
Mt. Tom	Yes	No	Yes	Expected by end of 2006
SESI	Sold	Yes	Yes	May 2006
Woods Electrical	Sold	Yes	Yes	April 2006
SECI-NH	Sold	Sold	Yes	November 2005
Woods Network	Sold	Sold	Yes	November 2005
E.S. Boulos Company	No	No	No	N/A

Assets Held for Sale: In November of 2005, NU decided to exit NU Enterprises retail marketing and competitive generation businesses. At December 31, 2005, management determined that the wholesale and retail marketing businesses did not meet the held for sale criteria under applicable accounting guidance.

In the first quarter of 2006, management determined that the retail marketing and competitive generation businesses now met held for sale criteria under applicable accounting guidance, and should therefore be recorded at the lower of carrying amount or fair value less cost to sell. In April of 2006, indicative bids for the competitive generation business were received. The retail marketing business was reduced to its fair value less cost to sell in the first half of 2006 by a $53.9 million pre-tax charge which was recorded in other operating expenses. The competitive generation assets are carried at their historical carrying value, which is less than their fair value less cost to sell. For further information see Note 12, "Segment Information," and Note 13, "Subsequent Events."

At June 30, 2006, management continues to believe the wholesale marketing business does not meet the held for sale criteria under applicable accounting guidance.

Certain assets and liabilities of Select Energy's retail marketing business remaining which will be assigned or transferred to Hess, are recorded at fair value less cost to sell and are included in assets held for sale and liabilities of assets held for sale.

The businesses above are included as part of the NU Enterprises reportable segment in Note 12, "Segment Information." The major classes of assets and liabilities that are held for sale at June 30, 2006 and December 31, 2005 are as follows (amounts at December 31, 2005 will not be comparable to amounts at June 30, 2006 as the assets held for sale portfolio has changed):

	At June 30, 2006	**At December 31, 2005**
(Millions of Dollars)		
Derivative contracts	$ 5.3	$ -
Property, plant and equipment	830.4	-
Long-term contract receivables	-	79.5
Other assets	21.2	22.3
Total assets	856.9	101.8
Derivative contracts	15.4	-
Long-term debt	318.3	86.3
Other liabilities	22.8	15.2
Total liabilities	356.5	101.5
Net assets	$500.4	$ 0.3

Discontinued Operations: NU's condensed consolidated statements of income/(loss) for all periods presented classify NGC, Mt. Tom, SESI and Woods Electrical in discontinued operations. In addition, SECI-NH (including Reeds Ferry) and Woods Network are included in discontinued operations for the three and six months ended June 30, 2005. These businesses were sold in November of 2005.

The retail marketing business is not presented as discontinued operations because separate financial information is not available for this business for the periods prior to the first quarter of 2006.

Under discontinued operations presentation, revenues and expenses of these businesses are classified net of tax in income from discontinued operations on the condensed consolidated statements of income/(loss), and all prior periods have been reclassified. These businesses are included as part of the NU Enterprises reportable segment in Note 12, "Segment Information." 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, 2006**	**June 30, 2005**	**June 30, 2006**	**June 30, 2005**
Operating revenue	$52.6	$83.5	$111.3	$171.6
Income/(loss) before income tax expense/(benefit)	20.4	18.5	38.8	11.5
Income tax expense/(benefit)	6.8	7.8	13.9	5.2
Net income/(loss)	7.9	10.7	18.5	6.3

On May 5, 2006, NU Enterprises completed the sale of SESI to Ameresco and recorded a pre-tax charge to income of $5.6 million ($3.3 million net of tax) in the second quarter of 2006.

Included in discontinued operations are $48.2 million and $98.3 million for the three and six months ended June 30, 2006, respectively, and $57.2 million and $113.4 million for the three and six months ended June 30, 2005, respectively, of intercompany revenues that are not eliminated in consolidation due to the separate presentation of discontinued operations. Of these amounts, $48.3 million and $98.1 million for the three and six months ended June 30, 2006, respectively, and $52.1 million and $105 million for the three and six months ended June 30, 2005, 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 expenses and losses are included in continuing operations.

At June 30, 2006, NU does not expect that after the disposal it will have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations.

5.

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

Contracts that are derivatives and do not meet the requirements to be treated as a cash flow hedge or normal purchases or normal sales 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, 2006 and December 31, 2005. At June 30, 2006 and December 31, 2005, derivative assets and liabilities of NU Enterprises have been segregated between wholesale, retail, generation and hedging amounts. The fair value of these contracts may not represent amounts that will be realized.

	At June 30, 2006				
(Millions of Dollars)	**Assets**		**Liabilities**		
	Current	**Long-Term**	**Current**	**Long-Term**	**Net Totals**
NU Enterprises:					
Wholesale	$103.1	$ 52.9	$(174.2)	$(137.5)	$(155.7)
Retail	5.2	0.1	(4.3)	-	1.0
Generation	7.1	-	(11.9)	(8.1)	(12.9)
Utility Group - Gas:					
Non-trading	0.2	-	-	-	0.2
Utility Group - Electric:					
Non-trading	58.4	267.3	(4.0)	(33.4)	288.3
NU Parent:					
Hedging	-	-	-	(14.5)	(14.5)
	174.0	320.3	(194.4)	(193.5)	106.4
Derivative assets and liabilities held for sale	(5.2)	(0.1)	7.4	8.0	10.1
Totals	$168.8	$320.2	$(187.0)	$(185.5)	$116.5

	At December 31, 2005				
(Millions of Dollars)	**Assets**		**Liabilities**		
	Current	**Long-Term**	**Current**	**Long-Term**	**Net Totals**
NU Enterprises:					
Wholesale	$256.6	$103.5	$(369.3)	$(220.9)	$(230.1)
Retail	55.0	12.9	(27.2)	0.4	41.1
Generation	9.2	-	(5.1)	(15.5)	(11.4)
Utility Group - Gas:					
Non-trading	0.1	-	(0.4)	-	(0.3)
Utility Group - Electric:					
Non-trading	82.6	308.6	(0.5)	(31.8)	358.9

NU Parent:					
Hedging	-	-	-	(5.2)	(5.2)
Totals	$403.5	$425.0	$(402.5)	$(273.0)	$153.0

The business activities of NU Enterprises that result in the recognition of derivative assets include exposures to credit risk to energy marketing and trading counterparties. At June 30, 2006 and December 31, 2005, Select Energy had derivative assets from wholesale, retail, generation, and hedging activities that are exposed to counterparty credit risk. However, a significant portion of these assets is contracted with investment grade rated counterparties or collateralized with cash.

NU Enterprises - Wholesale: Certain electricity and natural gas derivative contracts are part of Select Energy's 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 contracts to sell electricity to utilities under full requirements contracts, a contract to sell electricity to a municipality with a term of seven remaining years, and two contracts to purchase the output of generating plants. The fair value of electricity contracts was determined by prices from external sources for years through 2009 and by models based on natural gas prices and a heat-rate conversion factor to electricity for subsequent periods. The fair value of the natural gas contracts was primarily determined by prices provided by external sources and active markets.

Derivatives used in wholesale activities are recorded at fair value and included in the condensed consolidated balance sheets as derivative assets or liabilities. Changes in fair value are recorded in the period of change, mostly in wholesale contract market changes, net on the accompanying condensed consolidated statements of income/(loss).

NU Enterprises - Retail: On June 1, 2006, Select Energy closed on the sale of its retail marketing business to Hess and the related derivative assets and liabilities were transferred to Hess, except in cases where a customer has not yet consented to assignment. The remaining retail derivative assets and liabilities are recorded at fair value, which is determined using information from available external sources. During the first quarter of 2006, management was no longer able to conclude that physical delivery was probable under contracts that extended past the expected June 1, 2006 sale of the retail marketing business. As a result, retail marketing derivative contracts that were previously accounted for on an accrual basis under the normal purchase and sale exception were marked to market in the first quarter of 2006 and recognized in other operation expenses. At June 30, 2006, Select Energy had no hedges. A negative $2.2 million was recognized in earnings as of March 31, 2006 for the ineffective portion of cash flow hedges delivered through June 1, 2006. The retail marketing business was reduced to its fair value less cost to sell in the first half of 2006 by a $53.9 million pre-tax charge which was recorded in other operating expenses.

As of June 30, 2006, Select Energy has derivative assets and liabilities totaling $5.3 and $4.3 million, respectively, related to back-to-back agreements for electric and gas sourcing contracts for which Select Energy has not yet received consent from the customers to assign the contracts to Hess.

At December 31, 2005, Select Energy maintained natural gas service agreements with certain retail customers to supply gas at fixed prices for terms extending through 2010. New York Mercantile Exchange (NYMEX) futures contracts acquired to meet these commitments were recorded at fair value as derivative assets totaling $8.2 million and derivative liabilities of $0.3 million. Select Energy also maintained various financial instruments to hedge its electric and gas purchases and sales which included forwards, futures and swaps. At December 31, 2005, these hedging contracts, which were valued at the mid-point of bid and ask market prices, were recorded as derivative assets of $24.4 million and derivative liabilities of $4.8 million. These amounts were zero at June 30, 2006 because the contracts expired or were assigned to Hess.

Select Energy hedged certain amounts of natural gas inventory with gas futures that are accounted for as fair value hedges. Changes in the fair value of hedging instruments and natural gas inventory were recorded in fuel, purchased, and net interchange power. The change in fair value of the futures were included in derivative liabilities and amounted to $3.4 million at December 31, 2005. These amounts were zero at June 30, 2006 because the contracts expired or were assigned to Hess.

NU Enterprises - Generation: Derivative contracts include generation asset-specific sales and forward sales of electricity at hub trading points. The fair value of these contracts was determined by prices from external sources for the period of the contracts. Certain of these short-term forward purchase and sales contracts have been recorded at fair value in revenues, while other generation asset specific sales and forward sales of electricity at hub points qualified for accrual accounting until the fourth quarter of 2005 when Select Energy marked them to market because the probability of physical delivery could no longer be asserted. Changes in fair value of generation contracts formerly accounted for on an accrual basis are recorded in wholesale contract market changes, net for those contracts that are part of continuing operations. Changes in fair value of generation contracts that are held for sale are included in discontinued operations. These contracts extend through 2008.

Utility Group - Gas - Non-Trading: Yankee Gas s non-trading derivatives consist of peaking supply arrangements to serve winter load obligations and firm retail sales contracts with options to curtail delivery. These contracts are subject to fair value accounting as these contracts are derivatives that cannot be designated as normal purchase and sales because of the optionality in the contract terms. Non-trading derivatives at June 30, 2006 included assets of $0.2 million. At December 31, 2005, non-trading derivatives included assets of $0.1 million and liabilities of $0.4 million.

Utility Group - 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, 2006 include a derivative asset with a fair value of $325.2 million and a derivative liability with a fair value of $35.7 million. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of the stranded costs, and management believes that these costs will continue to be recovered or refunded in cost of service, regulated rates. At December 31, 2005, the fair values of these IPP non-trading derivatives included a derivative asset with a fair value of $391.2 million and a derivative liability with a fair value of $32.3 million.

CL&P has entered into Financial Transmission Rights (FTR) contracts to limit the congestion costs associated with its transitional standard offer (TSO) contracts. An offsetting regulatory asset has been recorded as this contract is part of the stranded costs and management believes that these costs will continue to be recovered in rates. At June 30, 2006, the fair value of these contracts is recorded as a derivative asset of $0.5 million and derivative liability of $1.7 million on the accompanying condensed consolidated balance sheets. The fair value of CL&P's FTRs at December 31, 2005 was zero.

NU Parent - Hedging: In March of 2003, 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. The changes in fair value of the swap and the hedged debt instrument are recorded on the condensed consolidated balance sheets and are equal and offsetting in the condensed consolidated statements of income/(loss). The cumulative change in the fair value of the hedged debt of $14.5 million is included as a decrease to long-term debt on the condensed consolidated balance sheets. The hedge is recorded as a derivative liability of $14.5 million at June 30, 2006, and $5.2 million at December 31, 2005. The resulting changes in interest payments made are recorded as adjustments to interest expense.

6.

GOODWILL AND OTHER INTANGIBLE ASSETS (Yankee Gas, NU Enterprises)

The only NU reporting unit that currently maintains goodwill is the Yankee Gas reporting unit, which is classified under the Utility Group - 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, 2006 and December 31, 2005.

As a result of NU s 2005 announcements to exit all of NU Enterprises' businesses, certain goodwill balances and intangible assets were deemed to be impaired. During the six months ended June 30, 2005, goodwill and intangible asset balances at the NU Enterprises energy services businesses were determined to be impaired, and $38.3 million in write-offs were recorded. In addition, $7.2 million of intangible assets, related to an exclusivity agreement held by the retail marketing business, were written off.

NU recorded amortization expense of $0.2 million and $1.1 million for the three and six months ended June 30, 2005, respectively, related to intangible assets subject to amortization.

7.

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 the rate reduction bonds, amortization of regulatory assets, and IPP over market costs, while the System Benefits Charge (SBC) allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes, and displaced worker protection costs.

On March 31, 2006, CL&P filed its 2005 CTA and SBC reconciliation with the Connecticut Department of Public Utility Control (DPUC), which compares CTA and SBC revenues to revenue requirements. For the year ended December 31, 2005, total CTA revenues exceeded the CTA revenue requirement by $60.1 million. This amount was recorded as a regulatory liability on the accompanying condensed consolidated balance sheets. For the same period, the SBC revenue requirement exceeded SBC revenues by $1.3 million. On July 24, 2006, the DPUC issued a final decision which approved the reconciliation of the CTA and SBC rates for the year 2005.

Income Taxes: In 2000, CL&P requested from the Internal Revenue Service (IRS) a Private Letter Ruling (PLR) regarding the treatment of unamortized investment tax credits (UITC) and excess deferred income taxes (EDIT) related to generation assets that were sold. On April 18, 2006, the IRS issued a PLR to CL&P regarding the treatment of UITC and EDIT related to generation assets that CL&P has sold. EDIT are temporary differences between book and taxable income that were recorded when the federal statutory tax rate was higher than it is now or when those differences were expected to be resolved. The PLR holds that it would be a violation of tax regulations if the EDIT or UITC is used to reduce customers' rates following the sale of the generation assets. CL&P was ordered by the DPUC to submit the PLR to the DPUC within 10 days of issuance and retain the UITC and EDIT in their existing accounts pending its receipt and review of the PLR.

CL&P's UITC balance is $59 million and EDIT balance is $15 million, totaling $74 million related to generation assets that have been sold. On July 27, 2006, the DPUC held that the UITC and EDIT amounts were no longer required to be held in their existing accounts. The $74 million balance will be reflected as a reduction of CL&P's third quarter 2006 income tax expense and will increase CL&P's earnings by the same amount.

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' PGA accounting methods and deferred any conclusion on the $9 million of previously recovered revenues until the completion of the audit. Management believes the unbilled sales and revenue adjustments and resultant charges to customers through the PGA clause were appropriate. Based on the facts of the case and the supplemental information provided to the DPUC, management believes the appropriateness of the PGA charges to customers for the time period under review will be approved.

New Hampshire:

DS, SCRC and ES Rates: On January 20, 2006, the New Hampshire Public Utilities Commission (NHPUC) approved a PSNH request to move reconciliation of its generation costs and revenues (including the prudency of its generation operations) from the Stranded Cost Recovery Charge (SCRC) to Energy Service (ES) proceedings. The change was effective on February 1, 2006.

On May 1, 2006, PSNH filed its 2005 SCRC reconciliation with the NHPUC, and proceedings have begun. While management believes that the operation of the generation business segment has been prudent and consistent with industry practices, it is unable to determine the impact, if any, of the NHPUC s review of the SCRC on PSNH s earnings or financial position.

On May 30, 2006, PSNH filed with the NHPUC to increase its delivery service (DS) rate by approximately $50 million, to decrease its SCRC to recognize the full recovery of its non-securitized part 3 stranded costs, and to decrease its ES rate to recognize changes in its power supply costs. On June 29, 2006, the NHPUC approved a temporary DS rate increase of $24.5 million, the requested decrease in the SCRC and a decrease in the ES rate. All rate changes were effective on July 1, 2006. The impact of the combined rate changes is an overall decrease of 15.5 percent. The temporary DS rate increase will be reconciled to the NHPUC decision in a full rate case to be decided in 2007, effective back to July 1, 2006.

Coal Procurement Docket: During the second quarter of 2006, the NHPUC opened a docket to review PSNH's coal procurement and coal transportation policies and procedures. PSNH is currently responding to data requests from the NHPUC's outside consultant. While management believes its coal procurement and transportation policies and procedures are prudent and consistent with industry practice, it is unable to determine the impact, if any, of the NHPUC's review on PSNH's earnings or financial position.

Environmental Legislation: In April of 2006, New Hampshire adopted legislation requiring PSNH to reduce the level of mercury emissions from its coal-fired plants by 2013 with incentives for early reductions. To comply with the legislation PSNH intends to install wet scrubber technology by mid-2013 at its two Merrimack coal units, which combined generate 433 megawatts (MW). PSNH currently estimates the cost to comply with this law to be approximately $250 million. However, this amount is subject to change as final design of the project is undertaken. State law and PSNH's restructuring agreement provide for the recovery of its generation costs, including the cost to comply with state environmental regulations.

Massachusetts:

Transition Cost Reconciliation: WMECO filed its 2005 transition cost reconciliation with the Massachusetts Department of Telecommunications and Energy (DTE) on March 31, 2006. This filing reconciles transition costs, default service costs and retail transmission costs with their associated revenues collected from customers. The DTE has not yet reviewed this filing or issued a schedule for review. Therefore the timing of a decision is uncertain at this time. Management does not expect the outcome of the DTE's review to have a material adverse impact on WMECO's earnings or financial position.

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 of its subsidiaries 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 $30 million of congestion charges previously withheld from NRG prior to the implementation of standard market design on March 1, 2003, which is still pending before the court, 2) the recovery of approximately $23.8 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. 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, Merchant Energy)

CL&P: These amounts represent commitments for various services and materials associated primarily with the Bethel, Connecticut to Norwalk, Connecticut, the Middletown, Connecticut to Norwalk, and the Norwalk to Northport-Long Island, New York transmission projects as of June 30, 2006.

(Millions of Dollars)	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
Transmission business							
project commitments	$159.1	$130.1	$128.8	$7.1	$2.9	$ -	$428.0

Merchant 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. The majority of these purchase commitments are being exited. Certain purchase commitments are accounted for on the accrual basis, while the remaining commitments are recorded at their mark-to-market value. These purchase commitments at June 30, 2006 are as follows:

(Millions of Dollars)	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
Select Energy purchase commitments	$768.4	$494.3	$150.3	$29.9	$5.3	$6.0	$1,454.2

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 wholesale, retail and generation energy commitments whose mark-to-market values have been recorded on the condensed consolidated balance sheets as derivative assets and liabilities, a portion of which is included in assets held for sale and liabilities of assets held for sale. 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.

Deferred Contractual Obligations (NU, CL&P, PSNH, WMECO)

CYAPC: On July 1, 2004, CYAPC filed with the FERC for recovery seeking to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning on January 1, 2005. On August 30, 2004, the FERC issued an order accepting the rates, with collection by CYAPC beginning on February 1, 2005, subject to refund.

The FERC staff filed testimony that recommended a total $38 million decrease in the requested rate increase, claiming that CYAPC should have used a different gross domestic product (GDP) escalator. NU's share of this recommended decrease is $18.6 million.

On November 22, 2005, a FERC administrative law judge issued an initial decision finding no imprudence on CYAPC's part. However, the administrative law judge did agree with the FERC staff s position that a lower GDP escalator should be used for calculating the rate increase and found that CYAPC should recalculate its decommissioning charges to reflect the lower escalator. Management expects that if the FERC staff's position on the decommissioning GDP cost escalator is found by the FERC to be more appropriate than that used by CYAPC to develop its proposed rates, then CYAPC would review whether to reduce its estimated decommissioning obligation and reduce its customers' obligations, including the obligation of CL&P, PSNH and WMECO.

The company believes that the costs have been prudently incurred and will ultimately be recovered from the customers of CL&P, PSNH and WMECO. However, there is a risk that some portion of these increased costs may not be recovered, or will have to be refunded if recovered, as a result of the FERC proceedings.

On June 10, 2004, the DPUC and the Connecticut Office of Consumer Counsel (OCC) filed a petition with the FERC seeking a declaratory order that CYAPC be allowed to recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but that such purchasers may not be allowed to recover in their retail rates any costs that the FERC might determine to have been imprudently incurred. The FERC rejected the DPUC's and OCC's petition, whereupon the DPUC filed an appeal of the FERC's decision with the D.C. Circuit Court of Appeals. The FERC and CYAPC have asked the court to dismiss the case, and the DPUC has objected to a dismissal. On June 13, 2006, the court decided not to take up the motion to dismiss until it reviews the case on the merits. A briefing schedule has not yet been set.

Parties to these proceedings are currently engaged in active settlement discussions, the outcome of which management cannot determine at this time.

YAEC: In November of 2005, YAEC established an updated estimate of the cost of completing the decommissioning of its plant. On January 31, 2006, the FERC issued an order accepting the rate increase, effective February 1, 2006, subject to refund by YAEC after hearings and settlement judge proceedings.

On May 1, 2006, YAEC filed with the FERC a settlement agreement with the DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service. Under the settlement agreement, YAEC agreed to revise its November 2005 decommissioning cost increase from $85 million to $79 million. The revision includes adjustments for contingencies and projected escalation and certain decontamination and dismantlement (D&D) expenses. Other terms of the settlement agreement include extending the collection period for charges through December 2014, reconciling and adjusting future charges based on actual D&D expenses and the decommissioning trust fund's actual investment earnings. The company believes that its share of the increase in decommissioning costs will ultimately be recovered from the customers of CL&P, PSNH and WMECO. NU has a 38.5 percent

ownership interest in YAEC. On July 31, 2006, the FERC approved the settlement agreement which then became effective and will not materially affect the level of 2006 charges.

MYAPC: MYAPC is collecting amounts in rates that are adequate to recover the remaining cost of decommissioning its plant.

Spent Nuclear Fuel Litigation: CYAPC, YAEC and MYAPC commenced litigation in 1998 charging that the federal government breached contracts it entered into with each company in 1983 under the Nuclear Waste Policy Act of 1982. The trial ended on August 1, 2004, and a verdict has not been reached. Post-trial findings of facts and final briefs were filed by the parties in January of 2005. The Yankee Companies' current rates do not include an amount for recovery of damages in this matter. Management can predict neither the outcome of this matter nor its ultimate impact on NU.

E.

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.

On March 5, 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). On March 12, 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

In an opinion dated October 12, 2005, 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. NU's request for a rehearing was denied on January 3, 2006. 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 opted not to seek review of this ruling by the United States Supreme Court. On April 7, 2006, NU filed its motion for partial summary judgment on Con Edison s damage claim. NU's motion asserts that NU is entitled to 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 stage, NU cannot predict the outcome of this matter or its ultimate effect on NU.

F.

Environmental Matters

Environmental reserves are accrued using a probabilistic model approach when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. The probabilistic model approach estimates the liability based on the most likely action plan from a variety of available remediation options, including no action is required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring.

These estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of contamination at the site, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

Remediation has been conducted at a coal tar contaminated river site in Massachusetts. Initial work indicates that the contamination could be more significant than currently estimated, but the level and extent of contamination is not yet known. An increase to the environmental reserve for this site could be recorded in earnings in future periods and could be material.

The amounts recorded as environmental liabilities on the condensed consolidated balance sheets represent management s best estimate of the liability for environmental costs and takes into consideration site assessment and remediation costs. Based on currently available information for estimated site assessment and remediation costs, these costs have increased by $3.6 million and $8.1 million during the three and six months ended June 30, 2006. At June 30, 2006 and December 31, 2005, NU had $31.8 million and $30.7 million, respectively, recorded as environmental reserves. A reconciliation of the activity in these reserves for the six months ended June 30, 2006 is as follows:

(Millions of Dollars)	
Balance at January 1, 2006	$30.7
Additions and adjustments	8.1
Payments	(7.0)
Balance at June 30, 2006	$31.8

Manufactured gas plant (MGP) sites comprise the largest portion of NU s environmental liability and the environmental reserves related to these sites increased by $8.2 million in the first half of 2006. MGPs are sites that manufactured gas from coal which produced certain byproducts that may pose a risk to human health and the environment. At June 30, 2006 and December 31, 2005,

$26.6 million and $25.3 million, respectively, represents amounts for the site assessment and remediation of MGPs. Of this amount, $3.0 million is included in liabilities of assets held for sale on the accompanying condensed consolidated balance sheet at June 30, 2006.

It is possible that new information or future developments could require a reassessment of the potential exposure to related environmental matters. As this information becomes available, management will continue to assess the potential exposure and adjust the reserves accordingly.

G.

Guarantees and Indemnifications

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 second quarter sales of SESI to Ameresco and the retail marketing business to Hess. The following table summarizes NU's maximum exposure at June 30, 2006, 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	Performance guarantees under government contracts.	$98.7	2019 - 2026 (1)	$0.2
	General indemnifications in connection with the sales of SESI including environmental issues, general product claims, compliance with laws, and other claims.	Not Specified (2)	None	-
		Not Specified (2)		0.2

	Specific indemnifications in connection with sale of SESI for estimated costs to complete or modify specific projects above specified levels.		Through project completion	
Hess (Retail Marketing)	Performance guarantee for retail marketing contract assigned to Hess for the sale of energy.	-	2007	-
	General indemnifications in connection with the sale including compliance with laws, validity of contract information, absence of default on contracts, and other claims.	Not Specified (2)	None	-

Subsidiary	**Description**	**Maximum Exposure (in millions)**	**Expiration Date(s)**	**Fair Value of Amounts Recorded (in millions)**
On behalf of subsidiaries:				
Utility Group	Surety bonds	$11.0	None	N/A
	Letters of credit	45.6	2006 - 2007	N/A
Rocky River Realty Company	Lease payments	11.5	2024	N/A
Energy Services Businesses	Performance and payment guarantees	76.1	2006 - 2007	N/A
Northeast Generation Company	Debt obligations	14.1	2026 (3)	N/A
Northeast Generation Services	Performance and payment guarantees	2.1	2006 - 2007	N/A
Select Energy	Performance guarantees for retail marketing contracts not yet assigned to Hess.	16.6 (4)	2006 - None (5)	N/A
	Performance guarantees for	296.6 (4)	None	N/A

wholesale marketing contracts.			
Letters of credit	71.1	2006	N/A

(1)

NU guarantees SESI's performance under government contracts financed by one investor. NU is permitted to and intends to terminate these guarantees prior to their annual anniversary dates over the next nine months. Upon notice of non-renewal, the investor can require NU to repurchase the underlying contract payments to satisfy the debt. Ameresco has a commitment from a

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lender to finance SESI s repurchase of these contract payments from NU. On July 7, 2006, the investor notified SESI that pursuant to financing terms it would require SESI to repurchase contract payments relating to the only guaranteed project that was behind schedule. SESI did not satisfy this requirement and on July 26, 2006, the contract payments were assigned to NU and NU paid the investor $10.4 million, $0.6 million of which will be recorded as a third quarter loss. NU recorded a $0.2 million loss to reflect the fair value of this guarantee in the second quarter. NU expects to sell the contract payments to SESI upon SESI's completion of the project which SESI would finance with its committed lender. NU may record additional losses associated with this transaction and associated with the planned termination of its other SESI guarantees, the amount of which will depend on the final calculation of contract payment purchase amounts, changes in interest rates used to determine Ameresco s financing proceeds, the amount of project cash available to offset NU s costs, and other factors.

(2)

There is no specified maximum exposure included in the related sale agreements. The estimated maximum exposure on the specific indemnifications associated with the SESI sale is $1.1 million. 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.

(3)

The guarantee will be terminated upon the sale of NGC's assets. See Note 13, "Subsequent Events," for more information regarding this sale.

(4)

Maximum exposure is as of June 30, 2006; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited.

(5)

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

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.

8.

MARKETABLE SECURITIES

The following is a summary of NU s available-for-sale securities related to NU's investment in Globix Corporation (Globix), NU's Supplemental Executive Retirement Plan (SERP) assets and WMECO's prior spent nuclear fuel trust assets, which are recorded at their fair values and are included in current and long-term marketable securities on the accompanying condensed consolidated balance sheets. Changes in the fair value of these securities are recorded as unrealized gains and losses in accumulated other comprehensive income:

	At June 30, 2006	At December 31, 2005
(Millions of Dollars)		
Globix investment	$ -	$ 3.7
SERP assets	59.5	58.1
WMECO prior spent nuclear fuel trust assets	51.9	50.8
Totals	$111.4	$112.6

NU had an investment in the common stock of NEON Communications, Inc. (NEON), a provider of optical networking services. On March 8, 2005, NEON merged with Globix. In connection with the closing of the merger, a $0.1 million after-tax loss was recognized in the first quarter of 2005 and a pre-tax positive $0.4 million change in fair value subsequent to March 8, 2005 was included in accumulated other comprehensive income. On April 6, 2006, NU sold its investment in Globix. This sale resulted in net proceeds of $6.7 million and a pre-tax gain of $3.1 million.

At June 30, 2006 and December 31, 2005, marketable securities are comprised of the following:

	At June 30, 2006			
(Millions of Dollars)	Amortized Cost	Pre-Tax Gross Unrealized Gains	Pre-Tax Gross Unrealized Losses	Estimated Fair Value
United States equity securities	$ 19.6	$4.2	$(0.5)	$ 23.3
Non-United States equity securities	5.3	1.5	-	6.8
Fixed income securities	82.4	0.1	(1.2)	81.3
Totals	$107.3	$5.8	$(1.7)	$111.4

	At December 31, 2005			
(Millions of Dollars)	Amortized Cost	Pre-Tax Gross Unrealized Gains	Pre-Tax Gross Unrealized Losses	Estimated Fair Value
United States equity securities	$ 23.2	$3.9	$(0.3)	$ 26.8
Non-United States equity securities	6.3	0.9	-	7.2
Fixed income securities	79.3	0.2	(0.9)	78.6
Totals	$108.8	$5.0	$(1.2)	$112.6

At June 30, 2006 and December 31, 2005, NU evaluated the securities in an unrealized loss position and has determined that none of the related unrealized losses are deemed to be other-than-temporary in nature. At June 30, 2006 and December 31, 2005, the gross unrealized losses and fair value of NU's investments that have been in a continuous unrealized loss position for less than 12 months and 12 months or greater were as follows:

	Less than 12 Months		12 Months or Greater		Total	
(Millions of Dollars) At June 30, 2006	Estimated Fair Value	Pre-Tax Gross Unrealized Losses	Estimated Fair Value	Pre-Tax Gross Unrealized Losses	Estimated Fair Value	Pre-Tax Gross Unrealized Losses

United States equity securities	$ 3.2	$(0.4)	$0.6	$(0.1)	$ 3.8	$(0.5)
Non-United States equity securities	-	-	-	-	-	-
Fixed income securities	40.9	(1.0)	4.2	(0.2)	45.1	(1.2)
Totals	$44.1	$(1.4)	$4.8	$(0.3)	$48.9	$(1.7)

	Less than 12 Months		**12 Months or Greater**		**Total**	
(Millions of Dollars) **At December 31, 2005**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**
United States equity securities	$ 2.9	$(0.2)	$0.4	$(0.1)	$ 3.3	$(0.3)
Non-United States equity securities	-	-	-	-	-	-
Fixed income securities	39.8	(0.7)	5.7	(0.2)	45.5	(0.9)
Totals	$42.7	$(0.9)	$6.1	$(0.3)	$48.8	$(1.2)

For information related to the change in net unrealized holding gains and losses included in shareholders' equity, see Note 9, "Comprehensive Income," to the condensed consolidated financial statements.

For the three and six months ended June 30, 2006 and 2005, realized gains and losses recognized on the sale of available-for-sale securities are as follows:

	Three Months Ended June 30,			**Six Months Ended June 30,**		
(Millions of Dollars)	**Realized Gains**	**Realized Losses**	**Net Realized Gains/(Losses)**	**Realized Gains**	**Realized Losses**	**Net Realized Gains/(Losses)**
2006	$3.6	$(0.4)	$ 3.2	$3.9	$(0.6)	$3.3
2005	$0.5	$(0.2)	$ 0.3	$0.6	$(0.4)	$0.2

Net realized gains of $3.4 million and $3.5 million for the three and six months ended June 30, 2006, respectively, and $0.3 million and $0.2 million for the three and six months ended June 30, 2005, respectively, are included in other income, net on the accompanying condensed consolidated statements of income/(loss). Net realized losses of $0.2 million and $0.2 million for the three and six months ended June 30, 2006, respectively, and $10 thousand and $21 thousand for the three and six months ended June 30, 2005, respectively, relating to the WMECO spent nuclear fuel trust are included in fuel, purchased and net interchange power on the accompanying condensed consolidated statements of income/(loss).

NU utilizes the specific identification basis method for the SERP securities and the average cost basis method for the WMECO prior spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities.

Proceeds from the sale of these securities, including proceeds from short-term investments, totaled $66.3 million and $84.7 million for the three and six months ended June 30, 2006, respectively. Of these amounts, $6.7 million relates to the proceeds from the sale of NU's investment in Globix. These amounts totaled $35.8 million and $54.5 million for the three and six months ended June 30, 2005, respectively.

At June 30, 2006, the contractual maturities of the available-for-sale securities are as follows:

(Millions of Dollars)	Amortized Cost	Estimated Fair Value
Less than one year	$ 31.9	$ 31.7
One to five years	27.8	27.6
Six to ten years	7.7	7.3
Greater than ten years	15.1	14.7
Subtotal	82.5	81.3
Equity securities	24.8	30.1
Total	$107.3	$111.4

9.

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, 2006 and 2005 is as follows:

For the 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:							
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 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

For the Three Months Ended June 30, 2005

(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net (loss)/income	$(27.7)	$11.0	$9.0	$2.4	$(47.1)	$(0.4)	$(2.6)
Comprehensive (loss)/income items:							
Cash flow hedging instruments	(1.9)	-	-	-	(0.9)	(1.0)	-
Unrealized losses on securities	(2.4)	-	-	-	(1.9)	-	(0.5)
Net change in comprehensive\ income items	(4.3)	-	-	-	(2.8)	(1.0)	(0.5)
Total comprehensive (loss)/income	$(32.0)	$11.0	$9.0	$2.4	$(49.9)	$(1.4)	$(3.1)

For the 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:							
	13.2	(4.6)	-	-	17.9	-	(0.1)

Cash flow hedging instruments							
Unrealized losses on securities	(0.2)	-	-	(0.1)	-	-	(0.1)
Other	2.4	-	-	-	-	-	2.4
Net change in comprehensive income 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

	For the Six Months Ended June 30, 2005						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net (loss)/income	$(145.4)	$36.2	$17.8	$7.1	$(214.5)	$14.5	$(6.5)
Comprehensive income/(loss) items:							
Cash flow hedging instruments	5.4	-	-	-	6.4	(1.0)	-
Unrealized losses on securities	(3.1)	-	-	(0.3)	(1.9)	-	(0.9)
Net change in comprehensive income items	2.3	-	-	(0.3)	4.5	(1.0)	(0.9)
Total comprehensive (loss)/income	$(143.1)	$36.2	$17.8	$6.8	$(210.0)	$13.5	$(7.4)

*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 cash flow hedging instruments for the six months ended June 30, 2006 and the twelve months ended December 31, 2005 are as follows:

(Millions of Dollars, Net of Tax)	Six Months Ended June 30, 2006	Twelve Months Ended December 31, 2005
Balance at beginning of period	$18.2	$(3.5)
Hedged transactions recognized into earnings	1.4	5.6
Amount reclassified into earnings due to discontinuation of cash flow hedges	(14.1)	-
Change in fair value	(1.7)	11.0
Cash flow transactions entered into for the period	1.2	5.1

Net change associated with the current period hedging transactions	(13.2)	21.7
Total fair value adjustments included in accumulated other comprehensive income	$ 5.0	$18.2

For the six months ended June 30, 2006, $1.3 million, net of tax, was reclassified from accumulated other comprehensive income in connection with the consummation of the underlying hedged transactions and recognized into earnings in revenues and fuel, purchased, and net interchange power and $0.1 million was reclassified into earnings related to the amortization of interest rate hedges. For the six months ended June 30, 2006, $14.1 million was reclassified from accumulated other comprehensive income into earnings (specifically included in other operation expenses) due to discontinuing cash flow hedge accounting and concluding that the retail marketing contracts being hedged beyond June 1, 2006 were no longer probable of physical delivery due to the retail business being sold. At June 30, 2006, it is estimated that $44 thousand included in the accumulated other comprehensive income balance will be reclassified as an increase to earnings in the next year.

In March of 2006, CL&P entered into a forward swap agreement to hedge the interest rate associated with $125 million of its planned $250 million, 30-year fixed rate 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 debt that was issued in June of 2006. On June 1, 2006, the hedged transaction was settled and as a result $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 life of the debt.

Accumulated other comprehensive income items unrelated to NU's cash flow hedging instruments totaled $0.4 million of losses and $1.8 million in gains at June 30, 2006 and December 31, 2005, respectively. These amounts relate to unrealized gains on investments in marketable debt and equity securities and minimum pension liability adjustments, net of related income taxes.

10.

EARNINGS PER SHARE (NU)

Earnings per share (EPS) is computed based upon the weighted average number of common shares outstanding, excluding unallocated Employee Stock Ownership Plan (ESOP) shares, during each period. Diluted EPS is computed on the basis of the weighted-average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common stock. Dilutive shares in the following table excludes 208,650 options and 1,255,929 options for the three months ended June 30, 2006 and 2005, respectively, and 218,650 options and 1,255,929 options for the six months ended June 30, 2006 and 2005, as these options were antidilutive. The weighted average common shares outstanding at June 30, 2006 include the impact of the issuance of 23 million common shares on December 12, 2005. The following table sets forth the components of basic and fully diluted EPS:

(Millions of Dollars, Except for Share Information)	**For the Three Months Ended June 30,**		**For the Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Income/(loss) from continuing operations	$14.3	$(38.4)	$(6.4)	$(151.7)
Income from discontinued operations	7.9	10.7	18.5	6.3
Net income/(loss)	22.2	(27.7)	12.1	(145.4)
Basic EPS common shares outstanding (average)	153,628,709	129,520,644	153,535,675	129,399,574
Dilutive effect	293,926	-	273,458	-
Fully diluted EPS common shares outstanding (average)	153,922,635	129,520,644	153,809,133	129,399,574
Basic and Fully Diluted EPS:				
Income/(loss) from continuing operations	0.09	(0.30)	(0.04)	(1.17)
Income from discontinued operations	0.05	0.09	0.12	0.05
Basic and fully diluted EPS	$0.14	$(0.21)	$0.08	$(1.12)

11.

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). The components of net periodic benefit expense for the Pension Plan and the PBOP Plan for the three and six months ended June 30, 2006 and 2005 are estimated as follows:

NU	**For the Three Months Ended June 30,**				**For the Six Months Ended June 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
Service cost	$ 12.4	$ 11.9	$ 2.2	$ 1.9	$ 24.7	$ 24.2	$ 4.1	$ 3.8

Interest cost	31.2	31.5	6.9	6.3	63.4	62.7	13.7	12.6
Expected return on plan assets	(42.9)	(42.9)	(3.5)	(2.8)	(86.4)	(85.9)	(7.0)	(5.6)
Amortization of unrecognized net transition (asset)/obligation	-	(0.1)	2.8	3.0	(0.1)	(0.2)	5.6	6.0
Amortization of prior service cost	1.4	1.8	(0.1)	(0.1)	3.0	3.6	(0.1)	(0.2)
Amortization of actuarial loss	9.0	8.6	-	-	19.4	16.7	-	-
Other amortization, net	-	-	4.5	4.3	-	-	9.0	8.6
Net periodic expense - before curtailments and termination benefits	11.1	10.8	12.8	12.6	24.0	21.1	25.3	25.2
Curtailment expense	(0.4)	-	-	-	(0.4)	-	-	-
Termination benefit expense	0.7	-	-	-	0.7	-	-	-
Total curtailments and termination benefits	0.3	-	-	-	0.3	-	-	-
Total - net periodic expense	$ 11.4	$ 10.8	$12.8	$12.6	$ 24.3	$ 21.1	$25.3	$25.2

A portion of these pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were approximately $2.6 million and $5.2 million for the three and six months ended June 30, 2006, respectively, and $2.3 million and $4.7 million for the three and six months ended June 30, 2005, respectively.

CL&P	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	Pension Benefits		Postretirement Benefits		Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2006	2005	2006	2005	2006	2005	2006	2005
Service cost	$ 4.2	$ 4.0	$ 0.7	$ 0.7	$ 8.6	$ 8.5	$ 1.4	$ 1.3
Interest cost	11.8	11.7	2.8	2.5	23.8	23.4	5.5	5.1
Expected return on plan assets	(20.3)	(19.9)	(1.4)	(1.1)	(40.6)	(39.9)	(2.8)	(2.2)
Amortization of unrecognized net transition obligation	-	-	1.5	1.6	-	-	3.0	3.1
Amortization of prior service cost	0.6	0.7	-	-	1.3	1.4	-	-
Amortization of actuarial loss	3.8	3.2	-	-	7.8	6.3	-	-
Other amortization, net	-	-	1.8	1.7	-	-	3.6	3.5
Net periodic expense - before curtailments termination benefits	0.1	(0.3)	5.4	5.4	0.9	(0.3)	10.7	10.8
Curtailment expense	(0.1)	-	-	-	(0.1)	-	-	-
Termination benefit expense	(0.4)	-	(0.1)	-	(0.4)	-	(0.1)	-
Total curtailments and termination benefits	(0.5)	-	(0.1)	-	(0.5)	-	(0.1)	-
Total - net periodic (income)/expense	$ (0.4)	$(0.3)	$ 5.3	$ 5.4	$ 0.4	$ (0.3)	$10.6	$10.8

Not included in the pension and postretirement benefits expense amounts above are intercompany allocations totaling $2.8 million and $1.9 million, respectively, for the three months ended June 30, 2006 and $2.1 million and $1.8 million, respectively, for the three months ended June 30, 2005. Amounts for pension and postretirement totaled $6.1 million and $3.9 million, respectively, for the six months ended June 30, 2006 and $4 million and $3.6 million, respectively, for the six months ended June 30, 2005.

For CL&P, a portion of the pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were $0.4 million and $1.4 million for the three and six months ended June 30, 2006, respectively, and $0.6 million and $1.3 million for the three and six months ended June 30, 2005, respectively.

PSNH	**For the Three Months Ended June 30,**				**For the Six Months Ended June 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
Service cost	$ 2.4	$ 2.2	$ 0.5	$ 0.4	$ 4.7	$ 4.4	$ 0.9	$ 0.8
Interest cost	4.9	4.8	1.3	1.1	10.0	9.5	2.5	2.2
Expected return on plan assets	(4.1)	(4.1)	(0.7)	(0.5)	(8.2)	(8.2)	(1.3)	(1.0)
Amortization of unrecognized net transition obligation	0.1	-	0.6	0.6	0.2	0.1	1.2	1.2
Amortization of prior service cost	0.3	0.4	-	-	0.6	0.8	-	-
Amortization of actuarial loss	1.4	1.3	-	-	2.9	2.4	-	-
Other amortization, net	-	-	0.9	0.8	-	-	1.7	1.5
Net periodic expense - before termination benefits	5.0	4.6	2.6	2.4	10.2	9.0	5.0	4.7
Termination benefit expense	0.1	-	-	-	0.1	-	-	-
Total - net periodic expense	$ 5.1	$ 4.6	$ 2.6	$ 2.4	$10.3	$ 9.0	$ 5.0	$ 4.7

Not included in the pension and postretirement benefits expense amounts above are intercompany allocations totaling $0.4 million and $0.3 million, respectively, for the three months ended June 30, 2006 and $0.5 million and $0.3 million, respectively, for the three months ended June 30, 2005. Amounts for pension and postretirement totaled $0.9 million and $0.7 million, respectively, for the six months ended June 30, 2006 and $0.9 million and $0.6 million, respectively, for the six months ended June 30, 2005.

For PSNH, a portion of these pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were $2 million and $3.4 million for the three and six months ended June 30, 2006, respectively, and $1.3 million and $2.6 million for the three and six months ended June 30, 2005, respectively.

WMECO	**For the Three Months Ended June 30,**				**For the Six Months Ended June 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
Service cost	$ 0.9	$ 0.8	$ 0.2	$ 0.1	$ 1.7	$ 1.6	$ 0.3	$ 0.3
Interest cost	2.4	2.3	0.6	0.6	4.8	4.6	1.2	1.1
Expected return on plan assets	(4.5)	(4.3)	(0.4)	(0.3)	(8.9)	(8.7)	(0.7)	(0.6)
Amortization of unrecognized net transition obligation	-	-	0.3	0.4	-	-	0.6	0.7
Amortization of prior service cost	0.1	0.2	-	-	0.3	0.4	-	-
Amortization of actuarial loss	0.8	0.7	-	-	1.6	1.3	-	-
Other amortization, net	-	-	0.4	0.3	-	-	0.8	0.7
Net periodic expense - before termination benefits	(0.3)	(0.3)	1.1	1.1	(0.5)	(0.8)	2.2	2.2
Termination benefit expense	(0.1)	-	-	-	(0.1)	-	-	-
Total - net periodic (income)/expense	$(0.4)	$(0.3)	$ 1.1	$ 1.1	$(0.6)	$(0.8)	$ 2.2	$ 2.2

Not included in the pension income and postretirement benefits expense amounts above are intercompany allocations totaling $0.5 million and $0.3 million, respectively, for the three months ended June 30, 2006 and $0.4 million and $0.3 million, respectively, for the three months ended June 30, 2005. Amounts for pension and postretirement totaled $1 million and $0.6 million, respectively, for the six months ended June 30, 2006 and $0.8 million and $0.7 million, respectively, for the six months ended June 30, 2005.

For WMECO, a portion of these pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were $0.1 million for both the three and six months ended June 30, 2006, respectively, and $0.1 million for the six months ended June 30, 2005. A de minimus amount was capitalized during the three months ended June 30, 2005. The capitalized amounts offset capital project costs, as pension income was recorded for all periods.

NU does not currently expect to make any contributions to the Pension Plan in 2006. NU contributed and anticipates contributing approximately $12.4 million quarterly totaling approximately $49.5 million in 2006 to fund its PBOP Plan.

Severance Benefits: As a result of its corporate reorganization, in 2005 NU recorded severance and termination benefits totaling $14.4 million relating to expected terminations of Utility Group and NUSCO employees. These severance benefits were recorded in other operating expenses because these amounts were for severance benefits under an existing benefit arrangement. NU also recorded $4.1 million, net of amounts capitalized, for pension and postretirement benefit plan curtailment losses relating to these employees and NU Enterprises employees that were expected to leave the company s benefit plans. Severance benefits for employees in the retail marketing and competitive generation businesses were not recorded in 2005 or in the first quarter of 2006 as management expected to sell these businesses as going concerns with the employees being transferred to the buyers.

In the second quarter of 2006, NU updated its prior estimates of Utility Group and NUSCO severance benefits based upon actual termination data and updated its estimates of expected head count reductions. A reduction in severance expense of $1.3 million was recorded and included in other operating expenses on the accompanying condensed consolidated statements of income/(loss) for the three months ended June 30, 2006, primarily due to a reduction in the expected number of terminated Utility Group and NUSCO employees. Adjustments to the pension plan curtailment losses and termination benefits expense were also recorded in the second quarter of 2006 totaling a $0.7 million reduction, net of amounts capitalized, in the curtailment losses and termination benefits expenses.

Also in the second quarter of 2006, NU recorded $4.3 million for severance and other employee benefits as these benefits became probable and estimable as a result of the sale of the retail marketing business to Hess. Of this amount, $0.6 million was for enhanced minimum benefits and was included in restructuring charges, with the remaining $3.7 million included in other operating expenses on the accompanying condensed consolidated statements of income/(loss)for the three and six months ended June 30, 2006 because these amounts were for severance benefits under an existing benefit arrangement.

12.

SEGMENT INFORMATION (All Companies)

Presentation: NU is organized between the Utility Group 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 they operate. Effective on January 1, 2005, the portion of Northeast Generation Services Company's (NGS) business that supports NGC's and HWP's generation assets has been reclassified from the services and other segment to the merchant energy segment within the NU Enterprises segment. 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.

Effective in the first quarter of 2006, separate financial information was prepared and used by management for each of the NU Enterprises merchant energy businesses it is exiting. Accordingly, separate detailed information is presented below for the wholesale and retail marketing and competitive generation businesses for the three months and six months ended June 30, 2006. It is not practicable to prepare comparable detailed information for any periods prior to the first quarter of 2006 due to the manner in which the merchant energy business operated prior to the first quarter of 2006.

The Utility Group segment, including the regulated electric, distribution, generation and transmission businesses, as well as the gas distribution business comprised of Yankee Gas, represents approximately 86 percent and 80 percent for the three and six months ended June 30, 2006, respectively, and 81 percent and 70 percent for the three and six months ended June 30, 2005, respectively, of NU's total revenues and includes the operations of the regulated electric utilities, CL&P, PSNH and WMECO, whose 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 businesses. Utility Group 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.

The NU Enterprises merchant energy business segment includes: 1) Select Energy, consisting of the wholesale and retail marketing businesses; and 2) NGC, NGS, and Mt. Tom, collectively referred to as the competitive generation business. The NU Enterprises services and other business segment includes E. S. Boulos Company, Woods Electrical, and NGS Mechanical, Inc., (which are subsidiaries of NGS), SESI, SECI, HEC/Tobyhanna Energy Project, Inc. and HEC/CJTS Energy Center LLC, and intercompany eliminations between the energy services businesses and merchant energy businesses. The results of NU Enterprises parent are also included within services and other.

Other in the tables includes the results for Mode 1 Communications, Inc., the results of the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, Yankee Energy Financial Services Company, and NorConn Properties, Inc.), the non-generation operations of HWP, and the results of NU's parent and service companies. Interest expense included in other primarily relates to the debt of NU parent.

Intercompany Transactions: Total Select Energy revenues from CL&P represented \$3.8 million and \$7.1 million for the three and six months ended June 30, 2006, respectively, and \$12.5 million and \$26.7 million for the three and six months ended June 30, 2005, respectively, of total NU Enterprises revenues. Total Select Energy sales to CL&P related to nontraditional standard offer contracts are eliminated in consolidation.

Total Select Energy revenues from transactions with WMECO represented \$0.5 million and \$1 million of total NU Enterprises revenues for the three and six months ended June 30, 2006, respectively, and \$17.4 million and \$37.9 million for the three and six months ended June 30, 2005, respectively. Total WMECO purchases from Select Energy are eliminated in consolidation.

Select Energy purchases from NGC and Mt. Tom represented \$48.3 million and \$98.1 million for the three and six months ended June 30, 2006, respectively. These amounts totaled \$52.1 million and \$105 million for NGC and Mt. Tom for the three and six months ended June 30, 2005, respectively.

Customer Concentrations: Select Energy revenues related to contracts with NSTAR companies represented \$82.2 million and \$288.6 million of total NU Enterprises revenues for the three and six months ended June 30, 2005, respectively. There were no sales to NSTAR for the three and six months ended June 30, 2006. Select Energy also provides basic generation service in the New Jersey and Maryland markets. Select Energy revenues related to these contracts represented \$117.9 million and \$250.5 million of total NU Enterprises revenues for the three and six months ended June 30, 2006, respectively, and \$73.5 million and \$143.2 million for the three and six months ended June 30, 2005, respectively. Select Energy revenues from Potomac Electric Power Company totaled \$46.3 million and \$112.9 million of total NU Enterprises' revenues for the three and six months ended June 30, 2006, respectively, and \$50.8 million and \$89.1 million for the three and six months ended June 30, 2005, respectively. No other individual customer represented in excess of 10 percent of NU Enterprises revenues for the three and six months ended June 30, 2006 and 2005.

Select Energy reported the settlement of all derivative wholesale contracts, 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 in the second quarter of 2005.

NU's segment information for the three and six months ended June 30, 2006 and 2005 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, 2006						
	Utility Group						
	Distribution (1)						
(**Millions of Dollars)**	**Electric**	**Gas**	**Transmission**	**NU Enterprises**	**Other**	**Eliminations**	**Total**
Operating revenues	$1,294.1	$ 88.4	$48.7	$246.6	$ 84.0	$(91.3)	$1,670.5
Depreciation and amortization	(88.2)	(5.6)	(7.4)	(0.1)	(4.6)	3.4	(102.5)
Wholesale contract market changes, net	-	-	-	(12.9)	-	-	(12.9)
Restructuring and impairment charges	-	-	-	(3.3)	-	-	(3.3)
Other operating expenses	(1,126.8)	(79.4)	(18.9)	(261.3)	(78.7)	88.5	(1,476.6)
Operating income/(loss)	79.1	3.4	22.4	(31.0)	0.7	0.6	75.2
Interest expense, net of AFUDC	(43.6)	(4.0)	(4.9)	(8.8)	(9.9)	7.9	(63.3)
Interest income	1.9	-	0.1	1.5	7.3	(8.1)	2.7
Other income/(loss), net	6.3	0.2	(0.7)	0.5	27.1	(23.4)	10.0
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)	$ 27.1	$(24.1)	$ 14.3
Income/(loss) from discontinued operations	-	-	-	7.9	-	-	7.9
Net income/(loss)	$ 20.9	$(0.1)	$ 12.7	$(14.3)	$ 27.1	$(24.1)	$ 22.2

	For the Six Months Ended June 30, 2006						
	Utility Group						
	Distribution (1)						
(Millions of Dollars)	**Electric**	**Gas**	**Transmission**	**NU Enterprises**	**Other**	**Eliminations**	**Total**
Operating revenues	$2,694.8	$ 272.5	$ 97.1	$ 773.6	$ 171.7	$ (191.8)	$ 3,817.9
Depreciation and amortization	(240.1)	(11.3)	(14.4)	(0.3)	(9.2)	6.9	(268.4)
Wholesale contract market changes, net	-	-	-	(19.7)	-	-	(19.7)
Restructuring and impairment charges	-	-	-	(8.4)	-	-	(8.4)
Other operating expenses	(2,303.4)	(235.6)	(38.6)	(883.0)	(161.6)	184.7	(3,437.5)
Operating income/(loss)	151.3	25.6	44.1	(137.8)	0.9	(0.2)	83.9
Interest expense, net of AFUDC	(85.7)	(8.5)	(9.5)	(17.4)	(18.7)	14.8	(125.0)
Interest income	5.4	-	0.2	3.6	14.5	(15.2)	8.5
Other income/(loss), net	16.5	0.2	(1.6)	0.3	87.6	(83.4)	19.6
Income tax (expense)/benefit	(34.3)	(5.6)	(7.2)	55.9	1.7	(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/(loss) from discontinued	-	-	-	18.5	-	-	18.5

operations							
Net income/(loss)	$ 51.0	$ 11.7	$ 25.4	$ (76.9)	$ 86.0	$ (85.1)	$ 12.1
Total assets (2)	$8,732.5	$1,159.0	$ -	$1,475.5	$4,642.4	$(4,550.4)	$11,459.0
Cash flows for total investments in plant	$ 148.7	$ 34.4	$172.5	$ 10.1	$ 15 .0	$ -	$ 380.7

	For the Three Months Ended June 30, 2005						
	Utility Group						
	Distribution (1)						
(Millions of Dollars)	**Electric**	**Gas**	**Transmission**	**NU Enterprises**	**Other**	**Eliminations**	**Total**
Operating revenues	$1,105.2	$88.3	$45.2	$301.9	$82.7	$(91.7)	$1,531.6
Depreciation and amortization	(107.1)	(5.5)	(6.0)	(0.4)	(4.5)	3.3	(120.2)
Wholesale contract market changes, net	-	-	-	(69.6)	-	-	(69.6)
Restructuring and impairment charges	-	-	-	(2.1)	-	-	(2.1)
Other operating expenses	(942.7)	(71.0)	(18.8)	(323.8)	(86.2)	86.7	(1,355.8)
Operating income/(loss)	55.4	11.8	20.4	(94.0)	(8.0)	(1.7)	(16.1)
Interest expense, net of AFUDC	(46.2)	(4.2)	(4.5)	(3.9)	(8.3)	3.8	(63.3)
Interest income	1.0	0.2	0.2	1.1	4.1	(4.7)	1.9
Other income/(loss), net	6.8	(0.1)	-	0.9	27.1	(26.3)	8.4
Income tax (expense)/benefit	(3.9)	(8.1)	(5.4)	38.1	11.2	0.2	32.1
Preferred dividends	(1.0)	-	(0.4)	-	-	-	(1.4)
Income/(loss) from continuing operations	12.1	(0.4)	10.3	(57.8)	26.1	(28.7)	(38.4)
Income from discontinued operations	-	-	-	10.7	-	-	10.7
Net income/(loss)	$ 12.1	$(0.4)	$10.3	$ (47.1)	$26.1	$(28.7)	$ (27.7)

For the Six Months Ended June 30, 2005

Utility Group

	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$2,280.6	$283.2	$ 81.9	$1,174.7	$168.8	$(224.6)	$3,764.6
Depreciation and amortization	(217.6)	(10.9)	(11.7)	(2.0)	(8.7)	6.6	(244.3)
Wholesale contract market changes, net	-	-	-	(258.5)	-	-	(258.5)
Restructuring and impairment charges	-	-	-	(23.7)	-	-	(23.7)
Other operating expenses	(1,924.3)	(242.1)	(34.1)	(1,234.1)	(160.7)	214.9	(3,380.4)
Operating (loss)/income	138.7	30.2	36.1	(343.6)	(0.6)	(3.1)	(142.3)
Interest expense, net of AFUDC	(87.6)	(8.4)	(7.4)	(7.4)	(16.3)	7.5	(119.6)
Interest income	1.7	0.2	0.3	1.6	8.2	(9.0)	3.0
Other income/(loss), net	12.0	(0.3)	(0.6)	0.2	73.6	(71.8)	13.1
Income tax (expense)/benefit	(20.3)	(7.2)	(9.0)	128.4	4.7	0.3	96.9
Preferred dividends	(2.1)	-	(0.7)	-	-	-	(2.8)
Income/(loss) from continuing operations	$ 42.4	$ 14.5	$ 18.7	$ (220.8)	$ 69.6	$ (76.1)	(151.7)
Income from discontinued operations	-	-	-	6.3	-	-	6.3
Net income/(loss)	$ 42.4	$ 14.5	$ 18.7	$ (214.5)	$ 69.6	$ (76.1)	$ (145.4)
Cash flows for total investments in plant	$ 207.2	$ 27.3	$ 85.0	$ 5.0	$ 7.6	$ -	$ 332.1

(1)

Includes PSNH's generation activities.

(2)

Information for segmenting total assets between electric distribution and transmission is not available at June 30, 2006. On a NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution column above.

Utility Group segment information related to the regulated electric distribution and transmission businesses for CL&P, PSNH and WMECO for the three and six months ended June 30, 2006 and 2005 is as follows:

	CL&P - For the Three Months Ended June 30, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$ 906.2	$ 34.1	$ 940.3
Depreciation and amortization	(57.8)	(5.5)	(63.3)
Other operating expenses	(814.9)	(12.2)	(827.1)
Operating income	33.5	16.4	49.9
Interest expense, net of AFUDC	(28.6)	(3.7)	(32.3)
Interest income	1.1	0.1	1.2
Other income/(loss), net	5.8	(0.8)	5.0
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**	**Totals**
Operating revenues	$ 1,878.2	$ 66.8	$ 1,945.0
Depreciation and amortization	(120.0)	(10.5)	(130.5)
Other operating expenses	(1,678.5)	(24.9)	(1,703.4)
Operating income	79.7	31.4	111.1
Interest expense, net of AFUDC	(55.6)	(7.0)	(62.6)
Interest income	4.3	0.1	4.4
Other income/(loss), net	14.6	(1.6)	13.0
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

	CL&P - For the Three Months Ended June 30, 2005		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$ 767.0	$ 30.6	$ 797.6
Depreciation and amortization	(65.0)	(4.5)	(69.5)
Other operating expenses	(671.8)	(12.4)	(684.2)

Operating income	30.2	13.7	43.9
Interest expense, net of AFUDC	(30.6)	(3.8)	(34.4)
Interest income	0.8	0.2	1.0
Other income/(loss), net	5.9	(0.1)	5.8
Income tax expense	(0.7)	(3.2)	(3.9)
Preferred dividends	(1.0)	(0.4)	(1.4)
Net income	$ 4.6	$ 6.4	$ 11.0

	CL&P - For the Six Months Ended June 30, 2005		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$ 1,581.9	$ 54.6	$ 1,636.5
Depreciation and amortization	(120.4)	(8.6)	(129.0)
Other operating expenses	(1,380.4)	(21.6)	(1,402.0)
Operating income	81.1	24.4	105.5
Interest expense, net of AFUDC	(57.1)	(5.8)	(62.9)
Interest income	1.5	0.3	1.8
Other income/(loss), net	11.0	(0.7)	10.3
Income tax expense	(10.4)	(5.3)	(15.7)
Preferred dividends	(2.1)	(0.7)	(2.8)
Net income	$ 24.0	$ 12.2	$ 36.2
Cash flows for total investments in plant	$ 117.3	$ 64.4	$ 181.7

	PSNH - For the Three Months Ended June 30, 2006		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues	$ 293.4	$10.0	$303.4
Depreciation and amortization	(27.0)	(1.3)	(28.3)
Other operating expenses	(228.8)	(4.7)	(233.5)
Operating income	37.6	4.0	41.6
Interest expense, net of AFUDC	(10.7)	(0.8)	(11.5)
Interest income	0.5	-	0.5
Other income, net	0.6	-	0.6
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**	**Totals**
Operating revenues	$598.1	$20.7	$618.8
Depreciation and amortization	(112.3)	(2.6)	(114.9)
Other operating expenses	(432.6)	(9.3)	(441.9)
Operating income	53.2	8.8	62.0
Interest expense, net of AFUDC	(21.4)	(1.6)	(23.0)
Interest income	0.7	-	0.7
Other income, net	1.3	-	1.3
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

	PSNH - For the Three Months Ended June 30, 2005		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues	$250.3	$ 9.3	$259.6
Depreciation and amortization	(37.6)	(1.1)	(38.7)
Other operating expenses	(193.5)	(3.9)	(197.4)
Operating income	19.2	4.3	23.5
Interest expense, net of AFUDC	(11.2)	(0.6)	(11.8)
Interest income	0.1	0.1	0.2
Other income, net	0.7	-	0.7

Income tax expense	(2.2)	(1.4)	(3.6)
Net income	$ 6.6	$ 2.4	$ 9.0

	PSNH - For the Six Months Ended June 30, 2005		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues	$510.6	$17.9	$528.5
Depreciation and amortization	(87.4)	(2.1)	(89.5)
Other operating expenses	(382.7)	(8.1)	(390.8)
Operating income	40.5	7.7	48.2
Interest expense, net of AFUDC	(22.1)	(1.1)	(23.2)
Interest income	0.2	0.1	0.3
Other income, net	0.7	-	0.7
Income tax expense	(5.8)	(2.4)	(8.2)
Net income	$ 13.5	$ 4.3	$ 17.8
Cash flows for total investments in plant	$ 74.4	$ 15.2	$ 89.6

(1)

Includes PSNH's generation activities.

	WMECO - For the Three Months Ended June 30, 2006		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$94.5	$ 4.7	$ 99.2
Depreciation and amortization	(3.3)	(0.6)	(3.9)
Other operating expenses	(83.1)	(2.1)	(85.2)
Operating income	8.1	2.0	10.1
Interest expense, net of AFUDC	(4.4)	(0.4)	(4.8)
Interest income	0.2	-	0.2
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	Totals
Operating revenues	$218.6	$ 9.6	$228.2
Depreciation and amortization	(7.9)	(1.2)	(9.1)
Other operating expenses	(192.3)	(4.5)	(196.8)
Operating income	18.4	3.9	22.3
Interest expense, net of AFUDC	(8.7)	(0.8)	(9.5)
Interest income	0.4	-	0.4
Other income, net	0.6	-	0.6
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

	WMECO - For the Three Months Ended June 30, 2005		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 88.1	$ 5.2	$ 93.3
Depreciation and amortization	(4.6)	(0.5)	(5.1)
Other operating expenses	(77.5)	(2.3)	(79.8)
Operating income	6.0	2.4	8.4
Interest expense, net of AFUDC	(4.4)	-	(4.4)
Interest income	0.1	-	0.1
Other income, net	0.1	-	0.1
Income tax expense	(0.9)	(0.9)	(1.8)

Net income	$ 0.9	$ 1.5	$ 2.4

	WMECO - For the Six Months Ended June 30, 2005		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$188.3	$9.4	$197.7
Depreciation and amortization	(9.8)	(1.0)	(10.8)
Other operating expenses	(161.4)	(4.4)	(165.8)
Operating income	17.1	4.0	21.1
Interest expense, net of AFUDC	(8.5)	(0.5)	(9.0)
Interest income	0.2	-	0.2
Other income, net	0.3	-	0.3
Income tax expense	(4.2)	(1.3)	(5.5)
Net income	$ 4.9	$2.2	$ 7.1
Cash flows for total investments in plant	$ 15.5	$5.4	$ 20.9

NU Enterprises' segment information for the six months ended June 30, 2006 and 2005 is as follows. The services and other column includes eliminations relating to the total merchant energy business and the energy services businesses.

	NU Enterprises	For the Three Months Ended June 30, 2006				
(Millions of Dollars)	**Wholesale**	**Retail**	**Generation**	**Total Merchant Energy**	**Services and Other**	**Totals**
Operating revenues	$ 0.8	$ 168.3	$ 66.1	$ 235.2	$ 11.4	$ 246.6
Depreciation and amortization	-	(0.1)	0.1	-	(0.1)	(0.1)
Wholesale contract market changes, net	(11.9)	-	(1.0)	(12.9)	-	(12.9)
Restructuring and impairment charges	(0.2)	0.1	(0.3)	(0.4)	(2.9)	(3.3)
Other operating expenses	5.4	(170.0)	(82.2)	(246.8)	(14.5)	(261.3)
Operating loss	(5.9)	(1.7)	(17.3)	(24.9)	(6.1)	(31.0)
Interest expense	(3.3)	(2.5)	(2.9)	(8.7)	(0.1)	(8.8)
Interest income	0.3	0.5	0.5	1.3	0.2	1.5
Other income/(loss), net	0.1	(0.1)	-	-	0.5	0.5
Income tax benefit	3.4	2.7	8.6	14.7	0.9	15.6
Loss from continuing operations	(5.4)	(1.1)	(11.1)	(17.6)	(4.6)	(22.2)
Income/(loss) from discontinued operations	-	-	12.3	12.3	(4.4)	7.9
Net (loss)/income	$ (5.4)	$ (1.1)	$ 1.2	$ (5.3)	$ (9.0)	$ (14.3)

	NU Enterprises	For the Six Months Ended June 30, 2006				
(Millions of Dollars)	**Wholesale**	**Retail**	**Generation**	**Total Merchant Energy**	**Services and Other**	**Totals**
Operating revenues	$ 10.1	$ 577.3	$ 161.0	$ 748.4	$ 25.2	$ 773.6

Depreciation and amortization	-	-	(0.1)	(0.1)	(0.2)	(0.3)
Wholesale contract market changes, net	(18.7)	-	(1.0)	(19.7)	-	(19.7)
Restructuring and impairment charges	(0.2)	(2.9)	(0.3)	(3.4)	(5.0)	(8.4)
Other operating expenses	3.2	(684.1)	(172.8)	(853.7)	(29.3)	(883.0)
Operating loss	(5.6)	(109.7)	(13.2)	(128.5)	(9.3)	(137.8)
Interest expense	(6.3)	(5.2)	(5.9)	(17.4)	-	(17.4)
Interest income	0.7	1.3	1.2	3.2	0.4	3.6
Other income/(loss), net	(0.4)	(0.1)	0.3	(0.2)	0.5	0.3
Income tax benefit	4.4	41.0	8.6	54.0	1.9	55.9
Loss from continuing operations	(7.2)	(72.7)	(9.0)	(88.9)	(6.5)	(95.4)
Income/(loss) from discontinued operations	-	-	23.9	23.9	(5.4)	18.5
Net (loss)/income	$ (7.2)	$ (72.7)	$ 14.9	$ (65.0)	$ (11.9)	$ (76.9)

	NU Enterprises - For the Three Months Ended June 30, 2005		
(Millions of Dollars)	**Total Merchant Energy**	**Services and Other**	**Totals**
Operating revenues	$ 277.0	$ 24.9	$ 301.9
Depreciation and amortization	(0.2)	(0.2)	(0.4)
Wholesale contract market changes, net	(69.6)	-	(69.6)
Restructuring and impairment charges	(2.1)	-	(2.1)
Other operating expenses	(295.8)	(28.0)	(323.8)
Operating loss	(90.7)	(3.3)	(94.0)
Interest expense	(3.8)	(0.1)	(3.9)
Interest income	0.7	0.4	1.1
Other income, net	0.9	-	0.9
Income tax benefit	36.9	1.2	38.1
Loss from continuing operations	(56.0)	(1.8)	(57.8)
Income/(loss) from discontinued operations	12.4	(1.7)	10.7
Net loss	$ (43.6)	$ (3.5)	$ (47.1)

(Millions of Dollars)	NU Enterprises - For the Six Months Ended June 30, 2005 Total Merchant Energy	Services and Other	Totals
Operating revenues	$1,124.1	$ 50.6	$1,174.7
Depreciation and amortization	(1.6)	(0.4)	(2.0)
Wholesale contract market changes, net	(258.5)	-	(258.5)
Restructuring and impairment charges	(23.7)	-	(23.7)
Other operating expenses	(1,165.3)	(68.8)	(1,234.1)
Operating loss	(325.0)	(18.6)	(343.6)
Interest expense	(7.2)	(0.2)	(7.4)
Interest income	1.0	0.6	1.6
Other loss, net	0.2	-	0.2
Income tax benefit	123.4	5.0	128.4
Loss from continuing operations	(207.6)	(13.2)	(220.8)
Income/(loss) from discontinued operations	25.2	(18.9)	6.3
Net loss	$(182.4)	$(32.1)	$ (214.5)

13.

SUBSEQUENT EVENTS

Competitive Generation Business: On July 24, 2006, NU reached an agreement with various subsidiaries of Energy Capital Partners (ECP) to sell its 100 percent ownership in NGC and HWP's 146-MW Mt. Tom coal-fired plant for $1.34 billion, including the assumption of $320 million of NGC debt. The sales of the NGC stock and the Mt. Tom plant require FERC approval and other approvals. The sale is expected to close by the end of 2006. Exclusive of income tax reserve, apportionment and other secondary impacts, NU currently expects to record an after-tax gain of approximately $300 million upon completion of the sale.

SESI Guarantee: For further information regarding the status of this issue, see Note 7G, "Commitments and Contingencies - Guarantees and Indemnifications."

CL&P PLR: For information regarding the current status of this issue, see Note 7A, "Commitments and Contingencies - Regulatory Developments and Rate Matters."

CYAPC: See Notes 1K, "Other Income, Net" and 7D, "Commitments and Contingencies - Deferred Contractual Obligations," for further information.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of
Northeast Utilities
Berlin, Connecticut

We have reviewed the accompanying condensed consolidated balance sheet of Northeast Utilities and subsidiaries (the "Company") as of June 30, 2006, and the related condensed consolidated statements of income/(loss) for the three-month and six-month periods ended June 30, 2006 and 2005, and of cash flows for the six-month periods ended June 30, 2006 and 2005. These interim financial statements are the responsibility of the Company s management.

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

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

As discussed in Notes 2 and 3, the Company recorded significant charges in the three-month and six-month periods ended June 30, 2006 and 2005 in connection with its decision to exit certain business lines. Also, as discussed in Note 4, prior period financial statements have been restated to include certain components of the Company s generation business as discontinued operations.

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, 2005, and the related consolidated statements of loss, comprehensive loss, shareholders equity, and cash flows for the year then ended (not presented herein); and in our report dated March 7, 2006 (June 7, 2006 as to Notes 1B, 1H, 1P, 1V, 2, 4, 12, 16, 17 and 18) (which report included an explanatory paragraph related to the recording of significant charges in connection with the Company s decision to exit certain business lines and the presentation of certain components of the Company s energy service businesses as discontinued operations), 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, 2005 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 4, 2006

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THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 19,762	$ 2,301
Investments in securitizable assets	272,131	252,801
Receivables, less provision for uncollectible accounts of $2,038 in 2006 and $1,982 in 2005	71,128	80,883
Accounts receivable from affiliated companies	885	17,214
Unbilled revenues	8,428	7,888
Materials and supplies	37,515	32,929
Derivative assets - current	58,368	82,578
Prepayments and other	13,111	18,003
	481,328	494,597
Property, Plant and Equipment:		
Electric utility	4,218,377	3,997,652
Less: Accumulated depreciation	1,217,284	1,175,164
	3,001,093	2,822,488
Construction work in progress	377,152	344,204
	3,378,245	3,166,692
Deferred Debits and Other Assets:		
Regulatory assets	1,367,610	1,357,985
Prepaid pension	315,430	315,532
Derivative assets - long-term	267,364	308,648

Other		116,107	121,618
		2,066,511	2,103,783
Total Assets	$	5,926,084	$ 5,765,072

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, 2006	December 31, 2005
	(Thousands of Dollars)	
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to affiliated companies	$ 125	$ 26,825
Accounts payable	332,422	253,974
Accounts payable to affiliated companies	44,187	39,755
Accrued taxes	19,069	60,531
Accrued interest	17,898	16,947
Derivative liabilities - current	3,950	477
Other	68,158	70,025
	485,809	468,534
Rate Reduction Bonds	783,262	856,479
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	837,216	774,190
Accumulated deferred investment tax credits	84,666	85,970
Deferred contractual obligations	204,732	243,279
Regulatory liabilities	595,050	742,993
Derivative liabilities - long-term	33,522	31,774
Other	135,009	131,253
	1,890,195	2,009,459
Capitalization:		
Long-Term Debt	1,513,732	1,258,883

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 2006 and 2005		60,352	60,352
Capital surplus, paid in		672,909	612,815
Retained earnings		399,286	382,628
Accumulated other comprehensive income/(loss)		4,339	(278)
Common Stockholder's Equity		1,136,886	1,055,517
Total Capitalization		2,766,818	2,430,600
Commitments and Contingencies (Note 7)			
Total Liabilities and Capitalization	$	5,926,084	$ 5,765,072

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,	
	2006	2005	2006	2005
	(Thousands of Dollars)			
Operating Revenues	$ 940,265	$ 797,568	$ 1,945,025	$ 1,636,469
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	602,283	486,311	1,267,210	1,022,996
Other	168,122	141,770	312,075	258,144
Maintenance	23,105	23,804	43,557	42,479
Depreciation	36,687	33,005	72,426	65,457
Amortization of regulatory (liabilities)/assets, net	(2,427)	9,462	(4,321)	5,208
Amortization of rate reduction bonds	29,070	26,998	62,523	58,378
Taxes other than income taxes	33,492	32,312	80,538	78,302
Total operating expenses	890,332	753,662	1,834,008	1,530,964
Operating Income	49,933	43,906	111,017	105,505
Interest Expense:				
Interest on long-term debt	17,339	15,182	33,653	27,957
Interest on rate reduction bonds	11,982	14,202	24,566	28,970
Other interest	2,979	5,042	4,424	5,944

Interest expense, net	32,300	34,426	62,643	62,871
Other Income, Net	6,177	6,888	17,392	12,054
Income Before Income Tax Expense	23,810	16,368	65,766	54,688
Income Tax Expense	6,338	3,925	14,464	15,712
Net Income	$ 17,472	$ 12,443	$ 51,302	$ 38,976

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,	
	2006	2005
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 51,302	$ 38,976
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	8,629	7,331
Depreciation	72,426	65,457
Deferred income taxes	56,230	14,715
Amortization of regulatory (liabilities)/assets, net	(4,321)	5,208
Amortization of rate reduction bonds	62,523	58,378
Deferral of recoverable energy costs	(30,858)	(1,845)
Pension expense	467	365
Regulatory refunds	(111,842)	(50,325)
Deferred contractual obligations	(33,475)	(29,506)
Other non-cash adjustments	(21,359)	(9,501)
Other sources of cash	19,008	4,474
Other uses of cash	(3,893)	(17,138)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	16,915	(3,241)
Materials and supplies	(4,586)	514
Investments in securitizable assets	(19,330)	(108,491)
Other current assets	4,950	5,762
Accounts payable	63,543	42,507
Accrued taxes	(41,462)	17,367
Other current liabilities	(2,051)	5,090

Net cash flows provided by operating activities		82,816		46,097
Investing Activities:				
Investments in plant		(240,040)		(181,672)
Proceeds from sales of investment securities		770		797
Purchases of investment securities		(796)		(818)
Net proceeds from sale of land		-		21,993
NU Money Pool investing		-		(8,375)
Other investing activities		(401)		1,243
Net cash flows used in investing activities		(240,467)		(166,832)
Financing Activities:				
Issuance of long-term debt		250,000		200,000
Retirement of rate reduction bonds		(73,217)		(68,363)
Capital contribution from Northeast Utilities		60,000		122,000
Decrease in short-term debt		-		(15,000)
Decrease in NU Money Pool borrowing		(26,700)		(90,025)
Cash dividends on preferred stock		(2,779)		(2,779)
Cash dividends on common stock		(31,865)		(26,918)
Other financing activities		(327)		(1,548)
Net cash flows provided by financing activities		175,112		117,367
Net increase/(decrease) in cash		17,461		(3,368)
Cash - beginning of period		2,301		5,608
Cash - end of period	$	19,762	$	2,240

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 80	$ 27
Receivables, less provision for uncollectible accounts of $2,376 in 2006 and $2,362 in 2005	94,015	95,599
Accounts receivable from affiliated companies	567	20,348
Unbilled revenues	42,316	47,705
Taxes receivable	14,858	-
Fuel, materials and supplies	77,490	72,820
Prepayments and other	11,780	11,987
	241,106	248,486
Property, Plant and Equipment:		
Electric utility	1,797,689	1,732,716
Other	5,816	5,816
	1,803,505	1,738,532
Less: Accumulated depreciation	717,002	698,480
	1,086,503	1,040,052
Construction work in progress	109,504	115,371
	1,196,007	1,155,423
Deferred Debits and Other Assets:		
Regulatory assets	428,858	821,951
Other	71,098	68,723
	499,956	890,674

Total Assets	$	1,937,069	$ 2,294,583

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, 2006	December 31, 2005
	(Thousands of Dollars)	
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to affiliated companies	$ 11,300	$ 15,900
Accounts payable	63,180	63,320
Accounts payable to affiliated companies	20,549	16,738
Accrued taxes	-	5,186
Accrued interest	8,198	8,202
Other	15,480	15,733
	118,707	125,079
Rate Reduction Bonds	358,620	382,692
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	202,165	242,590
Accumulated deferred investment tax credits	1,053	1,230
Deferred contractual obligations	40,217	48,262
Regulatory liabilities	131,721	414,558
Accrued pension	86,769	76,446
Other	44,986	44,136
	506,911	827,222
Capitalization:		
Long-Term Debt	507,092	507,086
Common Stockholder's Equity:		

Common stock, $1 par value - authorized 100,000,000 shares; 301 shares outstanding in 2006 and 2005		-		-
Capital surplus, paid in		212,226		209,788
Retained earnings		233,422		242,633
Accumulated other comprehensive income		91		83
Common Stockholder's Equity		445,739		452,504
Total Capitalization		952,831		959,590
Commitments and Contingencies (Note 7)				
Total Liabilities and Capitalization	$	1,937,069	$	2,294,583

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,	
	2006	2005	2006	2005
	(Thousands of Dollars)			
Operating Revenues	$ 303,438	$ 259,586	$ 618,754	$ 528,477
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	156,764	122,256	299,002	248,487
Other	45,590	45,377	88,158	88,790
Maintenance	22,246	21,075	35,737	35,110
Depreciation	12,229	11,523	24,453	22,841
Amortization of regulatory assets, net	4,144	15,771	66,220	43,708
Amortization of rate reduction bonds	11,975	11,350	24,166	22,913
Taxes other than income taxes	8,923	8,758	19,018	18,477
Total operating expenses	261,871	236,110	556,754	480,326
Operating Income	41,567	23,476	62,000	48,151
Interest Expense:				
Interest on long-term debt	5,959	5,102	11,683	9,874
Interest on rate reduction bonds	5,294	6,115	10,829	12,418
Other interest	215	546	445	909
Interest expense, net	11,468	11,763	22,957	23,201
Other Income, Net	1,143	884	2,030	980
	31,242	12,597	41,073	25,930

Income Before Income Tax Expense				
Income Tax Expense	16,338	3,534	21,037	8,079
Net Income	$ 14,904	$ 9,063	$ 20,036	$ 17,851

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, 2006	Six Months Ended June 30, 2005
	(Thousands of Dollars)	
Operating activities:		
Net income	$ 20,036	$ 17,851
Adjustments to reconcile to net cash flows		
provided by operating activities:		
Bad debt expense	1,994	1,040
Depreciation	24,453	22,841
Deferred income taxes	(18,081)	(23,021)
Amortization of regulatory assets, net	66,220	43,708
Amortization of rate reduction bonds	24,166	22,913
Pension expense	6,883	6,558
Regulatory (underrecoveries)/overrecoveries	(674)	2,571
Deferred contractual obligations	(7,594)	(6,153)
Other non-cash adjustments	(6,664)	3,754
Other sources of cash	-	6
Other uses of cash	(3,017)	(19,284)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	24,760	(12,217)
Fuel, materials and supplies	(4,670)	(4,545)
Other current assets	306	6,950
Accounts payable	8,673	9,562
Accrued taxes	(20,044)	12,225
Other current liabilities	(254)	437
Net cash flows provided by operating activities	116,493	85,196

Investing Activities:

Investments in plant		(60,408)		(89,651)
Proceeds from sales of investment securities		1,321		1,366
Purchases of investment securities		(1,365)		(1,401)
Other investing activities		(1,756)		(2,780)
Net cash flows used in investing activities		(62,208)		(92,466)
Financing Activities:				
Retirement of rate reduction bonds		(24,072)		(22,701)
Increase in short-term debt		-		10,000
(Decrease)/increase in NU Money Pool borrowing		(4,600)		12,600
Capital contribution from Northeast Utilities		2,500		15,000
Cash dividends on common stock		(29,247)		(12,256)
Other financing activities		1,187		(13)
Net cash flows (used in)/provided by financing activities		(54,232)		2,630
Net increase/(decrease) in cash		53		(4,640)
Cash - beginning of period		27		4,855
Cash - end of period	$	80	$	215

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 732	$ 1
Receivables, less provision for uncollectible accounts of $5,058 in 2006 and $3,653 in 2005	42,453	43,490
Accounts receivable from affiliated companies	295	5,752
Unbilled revenues	16,219	16,411
Taxes receivable	1,232	-
Materials and supplies	1,742	1,414
Marketable securities - current	24,994	20,905
Prepayments and other	863	897
	88,530	88,870
Property, Plant and Equipment:		
Electric utility	686,756	671,292
Less: Accumulated depreciation	197,129	193,151
	489,627	478,141
Construction work in progress	23,154	21,176
	512,781	499,317
Deferred Debits and Other Assets:		
Regulatory assets	231,154	223,174
Prepaid pension	81,292	80,618
Marketable securities - long-term	27,468	30,434
Other	21,782	23,583

		361,696		357,809
Total Assets	$	963,007	$	945,996

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, 2006	December 31, 2005
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 10,000	$ -
Notes payable to affiliated companies	15,200	14,900
Accounts payable	24,490	31,333
Accounts payable to affiliated companies	6,608	9,015
Accrued taxes	210	1,620
Accrued interest	4,553	4,517
Other	9,534	9,364
	70,595	70,749
Rate Reduction Bonds	105,293	111,331
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	227,308	219,992
Accumulated deferred investment tax credits	2,487	2,655
Deferred contractual obligations	56,001	66,633
Regulatory liabilities	24,162	23,836
Other	12,998	11,977
	322,956	325,093
Capitalization:		
Long-Term Debt	260,470	259,487
Common Stockholder's Equity:		
Common stock, $25 par value - authorized		

1,072,471 shares; 434,653 shares outstanding			
in 2006 and 2005		10,866	10,866
Capital surplus, paid in		103,295	82,811
Retained earnings		88,798	84,965
Accumulated other comprehensive income		734	694
Common Stockholder's Equity		203,693	179,336
Total Capitalization		464,163	438,823
Commitments and Contingencies (Note 7)			
Total Liabilities and Capitalization	$	963,007	$ 945,996

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(Thousands of Dollars)			
Operating Revenues	$ 99,162	$ 93,317	$ 228,202	$ 197,652
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	61,543	54,360	150,418	117,058
Other	17,431	18,386	32,953	34,380
Maintenance	3,521	4,197	7,353	8,035
Depreciation	4,234	4,041	8,527	8,068
Amortization of regulatory liabilities, net	(3,271)	(1,682)	(5,457)	(2,935)
Amortization of rate reduction bonds	2,953	2,768	5,987	5,615
Taxes other than income taxes	2,646	2,876	6,124	6,292
Total operating expenses	89,057	84,946	205,905	176,513
Operating Income	10,105	8,371	22,297	21,139
Interest Expense:				
Interest on long-term debt	2,678	2,149	5,422	4,326
Interest on rate reduction bonds	1,707	1,917	3,469	3,885
Other interest	394	410	642	747
Interest expense, net	4,779	4,476	9,533	8,958
Other Income, Net	242	322	1,006	459
Income Before Income Tax Expense	5,568	4,217	13,770	12,640

Income Tax Expense	2,939	1,849	5,964	5,545
Net Income	$ 2,629	$ 2,368	$ 7,806	$ 7,095

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, 2006	2005
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 7,806	$ 7,095
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	2,779	781
Depreciation	8,527	8,068
Deferred income taxes	8,172	123
Amortization of regulatory liabilities, net	(5,457)	(2,935)
Amortization of rate reduction bonds	5,987	5,615
Pension income	(343)	(348)
Regulatory (underrecoveries)/overrecoveries	(10,666)	6,658
Deferred contractual obligations	(9,215)	(8,018)
Other non-cash adjustments	(2,501)	(3,063)
Other sources of cash	3,293	1,039
Other uses of cash	-	(3,942)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	3,907	(2,472)
Materials and supplies	(328)	139
Other current assets	34	4,942
Accounts payable	(8,002)	5,263
Accrued taxes	(2,642)	2,107
Other current liabilities	389	(1,063)

Net cash flows provided by operating activities		1,740		19,989
Investing Activities:				
Investments in plant		(20,776)		(20,919)
Net proceeds from sale of land		-		1,599
Proceeds from sales of investment securities		55,799		31,597
Purchases of investment securities		(56,986)		(32,485)
Other investing activities		165		1,109
Net cash flows used in investing activities		(21,798)		(19,099)
Financing Activities:				
Retirement of rate reduction bonds		(6,038)		(5,666)
Increase/(decrease) in short-term debt		10,000		(15,000)
Increase in NU Money Pool borrowing		300		17,400
Capital contribution from Northeast Utilities		20,500		4,500
Cash dividends on common stock		(3,973)		(3,842)
Other financing activities		-		41
Net cash flows provided by/(used in) financing activities		20,789		(2,567)
Net increase/(decrease) in cash		731		(1,677)
Cash - beginning of period		1		1,678
Cash - end of period	$	732	$	1

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 2006 Form 10-Q and the NU 2005 Form 10-K as amended by NU's report on Form 8-K dated June 7, 2006 to classify certain businesses as discontinued operations. 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 $22.2 million, or $0.14 per share, in the second quarter of 2006, compared with a loss of $27.7 million, or $0.21 per share, in the second quarter of 2005. The results for 2006 included Utility Group net income of $33.5 million, or $0.22 per share, after payment of preferred dividends, NU Enterprises businesses losses of $14.3 million, or $0.10 per share, and parent company and other income of $3 million, or $0.02 per share.

- In the first half of 2006, NU earned $12.1 million, or $0.08 per share, compared with a loss of $145.4 million, or $1.12 per share, in the first half of 2005. The primary reason for the improved 2006 results were after-tax charges totaling $195.7 million ($306.3 million pre-tax) recorded in the first half of 2005 resulting from impairments and mark-to-market impacts associated with NU s decision to exit the wholesale marketing and energy services businesses.

- Utility Group results in the second quarter of 2006 included earnings of $12.7 million for the transmission businesses of The Connecticut Light & Power Company (CL&P), Public Service Company of New Hampshire (PSNH), and Western Massachusetts Electric Company (WMECO), compared with $10.3 million in the second quarter of 2005. For the first half of 2006, the transmission businesses earned $25.4 million, compared with $18.7 million in the first half of 2005. The higher transmission earnings were due primarily to a higher level of transmission investment on which these companies earned a return.

- Earnings at the distribution businesses of CL&P, PSNH, WMECO and Yankee Gas Services Company (Yankee Gas) and the regulated generation business of PSNH totaled $20.8 million in the second quarter of 2006 and $62.7 million in the first half of 2006, compared with $11.7 million in the second quarter of 2005 and $56.9 million in the first half of 2005. The earnings increase in 2006 was the result of the settlement of a CL&P tax case with the State of Connecticut in 2006, the full recovery in the second quarter of 2006 within pre-tax earnings of a deferred tax expense included in PSNH's non-securitized Part 3 stranded costs, while the associated tax expense is recorded on a pro-rata basis throughout 2006, and an after-tax charge of $4.4 million recorded in 2005 related to refunds to CL&P s streetlighting customers.

- Losses in the first half of 2006 for the NU Enterprises businesses were related primarily to the retail marketing business. That business, which was sold to Hess Corporation (Hess) on June 1, 2006, lost $1.1 million in the second quarter of 2006 and $72.7 million in the first half of 2006. A significant factor in the first half loss was related to an after-tax charge of $33.3 million which was recorded to reduce the book value of this business to its fair value less its cost to sell in order to reflect its held for sale status. NU Enterprises also recorded after-tax charges of $3.3 million ($5.6 million pre-tax) in the second quarter of 2006 to reflect the sale of Select Energy Services, Inc. (SESI) to Ameresco, Inc. (Ameresco). The improved 2006 results from 2005 reflect after-tax charges totaling $195.7 million ($306.3 million pre-tax) recorded in the first half of 2005 associated with exiting the wholesale marketing and energy services businesses.

- On July 24, 2006, NU reached an agreement with various subsidiaries of Energy Capital Partners (ECP) to sell its 100 percent ownership in Northeast Generation Company (NGC) and Holyoke Water Power Company's (HWP) 146 megawatt (MW) Mt. Tom coal-fired plant (Mt. Tom) for $1.34 billion, including the assumption of $320 million of NGC debt. The sale of the NGC stock and the Mt. Tom plant requires Federal Energy Regulatory Commission (FERC) approval and other approvals. The sale is expected to close by the end of 2006. Exclusive of income tax reserve, apportionment and other secondary impacts, NU currently expects to record an after-tax gain of approximately $300 million upon completion of the sale. The sales price is subject to final purchase price adjustments for working capital and other items.

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NU has revised its projection for 2006 combined earnings for the Utility Group and parent company from between $1.09 per share and $1.22 per share to between $1.57 per share and $1.70 per share as a result of the inclusion of a gain of $0.48 per share in CL&P s third quarter distribution results as a result of a one-time $74 million reduction of income tax expense pursuant to a private letter ruling (PLR) received from the Internal Revenue Service (IRS). NU is not providing consolidated earnings guidance or earnings guidance for NU Enterprises. NU has made significant progress in its strategic initiative to exit all of its competitive businesses. Upon the completion of the recently announced sale of its competitive generation business to ECP, NU will have divested or sold substantially all of NU Enterprises assets. As a result of divestitures, NU s annual revenues are projected to decrease by approximately $2 billion from 2005 levels.

Regulatory Items:

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On June 15, 2006, the FERC approved a settlement agreement which proposed a Forward Capacity Market (FCM) in place of the previously proposed Locational Installed Capacity (LICAP) pricing mechanism. The settlement was filed by the New England Independent System Operator (ISO-NE) and a broad cross-section of critical stakeholders from around the region, including CL&P, PSNH and Select Energy, Inc. (Select Energy) at the FERC. The settlement agreement is expected to be implemented by December 1, 2006. Several parties have sought rehearing of this issue by the FERC.

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On June 29, 2006, the New Hampshire Public Utilities Commission (NHPUC) approved a temporary Delivery Service (DS) rate increase of $24.5 million, the requested decrease in the Stranded Cost Recovery Charge (SCRC) and a decrease in the Energy Service (ES) rate. All rate changes were effective on July 1, 2006. The impact of the combined rate changes is an overall decrease of 15.5 percent.

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On July 20, 2006, the FERC issued its final rules promoting transmission investment through pricing reform that included the financial incentives for the construction of high-voltage electric transmission in the United States. The final rule identifies specific incentives the FERC will allow when justified in the context of specific rate applications. Management views this rule to be positive, but the actual impacts on NU will be determined by the specific incentives that NU seeks and that are approved by the FERC.

- On July 27, 2006, the Connecticut Department of Public Utility Control (DPUC) issued a letter releasing its hold on unamortized investment tax credits (UITC) and excess deferred income taxes (EDIT) pursuant to a PLR from the IRS. The $74 million of UITC and EDIT will be reflected as a reduction of CL&P's third quarter 2006 income tax expense and will increase CL&P's earnings by the same amount.

- On August 4, 2006, CL&P notified Governor Rell and the DPUC that it intends to postpone filing a distribution rate case until mid-2007 for rates effective on January 1, 2008.

Liquidity:

- NU's capital expenditures totaled $380.7 million in the first half of 2006, compared with $332.1 million in the first half of 2005. The increase in NU's capital expenditures was primarily the result of higher transmission capital expenditures, particularly at CL&P. Utility Group capital expenditures are expected to approach approximately $900 million in 2006.

- Cash flows from operations decreased by $65.3 million from $278.4 million for the first half of 2005 to $213.1 million for the first half of 2006. The decrease in operating cash flows is due primarily to higher regulatory refunds in 2006 as CL&P refunded amounts to its ratepayers to moderate the increase in CL&P's transitional standard offer (TSO) rates that became effective on January 1, 2006, a higher level of recoverable energy costs paid but not yet recovered in regulated rates, and a federal income tax payment of approximately $55 million in the first quarter of 2006 related to NU's 2005 tax return.

<u>Overview</u>

Consolidated: NU earned $22.2 million, or $0.14 per share, in the second quarter of 2006, compared with a loss of $27.7 million, or $0.21 per share, in the second quarter of 2005. NU earned $12.1 million, or $0.08 per share, in the first half of 2006, compared with a loss of $145.4 million, or $1.12 per share, in the first half of 2005. Earnings per share results in 2006 include the impact of the issuance of 23 million NU common shares on December 12, 2005. A summary of NU's earnings/(losses) by major business line for the second quarter and first half of 2006 and 2005 is as follows:

(Millions of Dollars, except per share amounts)	For the Three Months Ended June 30, 2006 Amount	Per Share	2005 Amount	Per Share	For the Six Months Ended June 30, 2006 Amount	Per Share	2005 Amount	Per Share
Utility Group	$33.5	$0.22	$ 22.0	$ 0.17	$88.1	$0.58	$ 75.6	$ 0.58
NU Enterprises	(14.3)	(0.10)	(47.1)	(0.36)	(76.9)	(0.50)	(214.5)	(1.65)
Parent and Other	3.0	0.02	(2.6)	(0.02)	0.9	-	(6.5)	(0.05)
Net (Loss)/Income (1)	$22.2	$0.14	$(27.7)	$(0.21)	$12.1	$0.08	$(145.4)	$(1.12)

(1)

The segments above do not necessarily coincide with the legal entities that have exchangeable securities. Instead, the segments reflect how management views the financial performance of its businesses. As such, the shareholders of NU do not have a direct legal right to the assets and liabilities of any one segment but do have a right to part of NU's assets and liabilities as a whole.

A portion of NU Enterprises results are included in discontinued operations. See the Overview   NU Enterprises section included in this management's discussion and analysis for further information.

Within the Utility Group, NU segments its earnings between its transmission and distribution businesses with regulated generation included in the distribution business. The electric transmission business earned $12.7 million in the second quarter of 2006 and $25.4 million in the first half of 2006, compared with $10.3 million in the second quarter of 2005 and $18.7 million in the first half of 2005. The higher level of transmission earnings was due primarily to a return on a higher level of transmission investment at CL&P.

In the second quarter of 2006, the electric distribution and regulated generation companies earned $20.9 million, compared with $12.1 million in the second quarter of 2005. Those companies earned $51 million in the first half of 2006, compared with $42.4 million in the same period of 2005. Yankee Gas lost $0.1 million in the second quarter of 2006 and earned $11.7 million in the first half of 2006, compared with a loss of $0.4 million in the second quarter of 2005 and earnings of $14.5 million in the first half of 2005. The decline in the first half of 2006 earnings at Yankee Gas was primarily due to an 11.5 percent decline in firm gas sales, mostly caused by milder weather.

In the first half of 2006, the NU Enterprises businesses accounted for approximately 20 percent of NU's revenues and at June 30, 2006, these businesses also accounted for approximately 13 percent of NU's total assets. NU Enterprises is comprised of the wholesale marketing, competitive generation, and the energy services businesses. It also included the results of the retail marketing business, which was sold to Hess on June 1, 2006. Through July of 2006, NU had also sold four of its six energy services businesses and portions of a fifth.

In the first half of 2006, the NU Enterprises loss was primarily related to its retail marketing business. NU Enterprises' retail marketing business lost $1.1 million in the second quarter of 2006, almost all of it prior to the June 1, 2006 sale to Hess. An after-tax charge of $33.3 million ($53.9 million pre-tax) was recorded in the first half of 2006 to reduce the book value of this business to its fair value less its cost to sell. In addition to the retail marketing business charge, NU Enterprises lost $43.6 million in the first half of 2006. The primary reason for the improved 2006 results were after-tax charges totaling $195.7 million ($306.3 million pre-tax) recorded in the first half of 2005 resulting from impairments and mark-to-market impacts associated with NU s decision to exit the wholesale marketing and energy services businesses.

Utility Group: The Utility Group is comprised of CL&P, PSNH, WMECO and Yankee Gas, and is comprised of their applicable transmission, distribution and generation businesses. A summary of Utility Group earnings by company and business segment for the three and six months ended June 30, 2006 and 2005 is as follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**
CL&P Distribution	$ 6.4	$ 4.6	$29.8	$24.0
CL&P Transmission	9.7	6.4	18.8	12.2
Total CL&P *	16.1	11.0	48.6	36.2
PSNH Distribution and Generation	12.9	6.6	15.4	13.5
PSNH Transmission	2.0	2.4	4.6	4.3
Total PSNH	14.9	9.0	20.0	17.8
WMECO Distribution	1.6	0.9	5.8	4.9
WMECO Transmission	1.0	1.5	2.0	2.2
Total WMECO	2.6	2.4	7.8	7.1
Total Distribution and Generation	20.9	12.1	51.0	42.4
Total Transmission	12.7	10.3	25.4	18.7
Yankee Gas	(0.1)	(0.4)	11.7	14.5
Total Utility Group Net Income	$33.5	$22.0	$88.1	$75.6

*After preferred dividends in all periods.

CL&P's second quarter and first half of 2006 distribution earnings increased as a result of higher distribution rates and an after-tax charge of $4.4 million recorded in the second quarter of 2005 related to refunds to streetlighting customers offset by lower sales and higher interest and operating expenses in 2006. CL&P's distribution earnings for the first half of 2006 also increased as a result of a lower effective tax rate resulting from the settlement of a tax case with the State of Connecticut which improved CL&P's 2006 first quarter net income by $4.9 million. CL&P s regulatory return on equity (ROE) on a trailing 12-month basis is now approximately 7.7 percent compared to its allowed ROE of 9.85 percent.

Second quarter and first half 2006 CL&P transmission earnings benefited from higher revenues due to earnings on a higher level of investment in its transmission system.

PSNH's distribution and generation earnings in the second quarter of 2006 and first half of 2006 were higher than similar periods in 2005 primarily due to the full recovery in the second quarter of 2006 within pre-tax earnings of a deferred tax expense included in PSNH's non-securitized Part 3 stranded costs. However, the associated tax expense will be recorded on a pro-rata basis throughout 2006 and will have no impact on PSNH's net income in 2006. PSNH s regulatory ROE on a trailing 12-month basis is now approximately 6.9 percent.

PSNH's transmission earnings for the second quarter were lower due to the true-up of prior period expenses partially offset by higher earnings resulting from higher rate base. PSNH transmission earnings for the first half of 2006 benefited from higher rate base earnings, partially offset by the true-up of prior period expenses.

WMECO's improved second quarter and first half of 2006 distribution results were higher due to a $3 million annualized distribution rate increase that took effect on January 1, 2006 offset by a 2.7 percent decrease in sales and increased interest expense in the first half of 2006. WMECO's regulatory ROE on a trailing 12-month basis is now approximately 10 percent compared to its allowed ROE of 9.85 percent.

WMECO's transmission earnings for the second quarter and first half of 2006 were lower due to the true-up of prior period expenses partially offset by higher rate base earnings in both periods.

Yankee Gas' first half of 2006 results were lower than the same periods of 2005 primarily as a result of an 11.5 percent decline in firm natural gas retail sales, mostly caused by milder weather during the 2006 heating season. Yankee Gas regulatory ROE on a trailing 12-month basis is now approximately 6.8 percent compared to its allowed ROE of 9.9 percent.

The Utility Group's first half of 2006 retail electric sales were negatively affected by temperatures that were milder in the first quarter of 2006 than during the same periods of 2005 and by price elasticity driven by higher energy prices in 2006. Overall, retail kilowatt-hour (kWh) electric sales decreased by 2.5 percent in the second quarter of 2006 from the second quarter of 2005 (a 0.6 percent decrease on a weather-normalized basis). Retail electric sales decreased by 3 percent in the first half of 2006 (a 0.8 percent decrease on a weather-normalized basis) compared with the first half of 2005. Residential electric sales in the first half of 2006 decreased by 5.2 percent from 2005; commercial electric sales decreased by 1 percent; and industrial sales decreased by 2.2 percent. Absent the impacts of the weather, management believes the decline in sales is due primarily to higher prices driven by the higher fuel and purchased power costs.

NU Enterprises: At June 30, 2006, NU Enterprises was the parent of Select Energy, NGC, Northeast Generation Services Company (NGS) and its subsidiary, E.S. Boulos Company (Boulos), Select Energy Contracting, Inc. - Connecticut (SECI-CT), which is a division of Select Energy Contracting, Inc. (SECI), all of which are collectively referred to as "NU Enterprises." The generation operations of HWP's Mt. Tom plant are also included in the results of NU Enterprises.

The merchant energy business includes Select Energy's wholesale marketing and retail marketing businesses, 1,442 MW of generation assets, including 1,296 MW of primarily pumped storage and hydroelectric generation assets at NGC and 146 MW of coal-fired generation assets at HWP related to Mt. Tom, and NGS. At June 30, 2006, the energy services businesses include the operations of Boulos, and SECI-CT.

NU s condensed consolidated statements of income/(loss) for the three and six months ended June 30, 2006 and 2005 present the operations for the following companies as discontinued operations:

- NGC,
- Mt. Tom,
- SESI, which was sold in May of 2006 to Ameresco, Inc.,
- Woods Electrical Co., Inc. (Woods Electrical), which was sold in April of 2006 to WESDAC, LLC.
- Select Energy Contracting, Inc. - New Hampshire (SECI-NH) (including Reeds Ferry Supply Co., Inc. (Reeds Ferry)), which was sold in November of 2005 to Denron Plumbing & HVAC, LLC., and
-

Woods Network Services, Inc. (Woods Network), which was sold in November of 2005 to Barn Systems, Inc.

NU Enterprises' wholesale and retail marketing businesses are not included in discontinued operations because they do not meet the accounting criteria for this presentation.

A summary of NU Enterprises' losses for the three and six months ended June 30, 2006 and 2005 is as follows:

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**
Merchant Energy	$ (5.3)	$(43.6)	$(65.0)	$(182.4)
Energy Services, Parent and Other	(9.0)	(3.5)	(11.9)	(32.1)
Net Loss	$(14.3)	$(47.1)	$(76.9)	$(214.5)

A summary of NU Enterprises' losses from continuing operations and discontinued operations for the three and six months ended June 30, 2006 and 2005 is as follows:

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**
Continuing Operations:				
Merchant Energy	$ (17.6)	$(56.0)	$(88.9)	$(207.6)
Energy Services, Parent and Other	(4.6)	(1.8)	(6.5)	(13.2)
	(22.2)	(57.8)	(95.4)	(220.8)
Discontinued Operations:				
Merchant Energy	12.3	12.4	23.9	25.2
Energy Services, Parent and Other	(4.4)	(1.7)	(5.4)	(18.9)
	7.9	10.7	18.5	6.3
Net Loss	$(14.3)	$(47.1)	$(76.9)	$(214.5)

The earnings included in discontinued operations relate to NGC's and Mt. Tom's contracts with Select Energy. Retail marketing results are included as continuing operations, as separate financial information for the retail marketing business is not available due to the manner in which the merchant energy business operated prior to January 1, 2006.

The retail marketing business loss from operations totaling $1.1 million for the second quarter and $72.7 million for the first half of 2006 reflects the operating margins of the retail marketing business being more than offset by its ongoing operating expenses and a $33.3 million negative after-tax adjustment to record the retail business at fair value less cost to sell, which partially reflects the impacts of the decision to exit the wholesale marketing business.

In addition to the charge to reflect the fair value of the retail marketing business, results for the first half of 2006 reflect the losses from both the electric sales and natural gas sales. The losses for electric sales were caused primarily by replacing the electricity supply at current prices. When the decision to exit the competitive generation and retail marketing businesses was announced, the resources of the competitive generation business that were previously dedicated to the retail marketing business at a fixed price were separated from the retail marketing business, exposing the portfolio of retail sales to current market prices. Market prices have generally been higher than those that would have been charged by the competitive generation business (with generation receiving a partially offsetting benefit). The retail marketing losses on natural gas were primarily the results of mild weather which lowered demand and created a surplus of supply which was either sold at a loss or remained in storage with a reduced fair value.

Contributing to the negative results totaling $4.2 million in the second quarter of 2006 for the combined wholesale marketing and competitive generation businesses was an after-tax loss of $9.2 million due to changes in the fair value of the wholesale marketing contracts compared to an after-tax gain of $4 million on these contracts in the first quarter of 2006. The combined wholesale marketing and competitive generation businesses recorded earnings of $7.7 million in the first half of 2006. Short-term energy prices in the second quarter of 2006 continued to decrease and reduced the value received from sales of generation products compared to the first quarter of 2006, which contributed to the second quarter 2006 loss. However, generation earnings are higher in 2006 than the first half of last year because generation is selling its products into a market that is generally higher than if it would have sold those products to the retail marketing business.

The combined wholesale marketing and competitive generation businesses losses in the second quarter of 2005 and the first half of 2005 totaling $45 million and $180.6 million, respectively, reflect the impacts of NU s March 2005 decision to exit the wholesale marketing business. As a result of that decision, third party sales contracts and the majority of contracts intended to source a combination of retail and wholesale loads were marked to market.

The losses at the energy services businesses, parent and other are primarily due to increases in the costs to complete certain SECI contracts and restructuring charges associated with Woods Electrical, SESI and SECI-CT. A $3.3 million after-tax loss is included in the second quarter as a result of the sale of SESI. The improved results in the first half of 2006 are due to the absence of comparable restructuring and impairment charges in 2006 recorded in the first quarter of 2005.

For information regarding the current status of the exit from the wholesale marketing, retail marketing, competitive generation and energy services businesses, see "NU Enterprises Divestitures," included in this management's discussion and analysis.

Parent and Other: Parent company and other after-tax income totaled $3 million in the second quarter and $0.9 million in the first half of 2006, compared with expenses of $2.6 million in the second quarter and $6.5 million in the first half of 2005. Improved second quarter results were due to higher investment income in 2006 and a $2 million after-tax gain associated with the sale of NU's 2.7 million shares of Globix Corporation (Globix), a telecommunications company.

Future Outlook

NU has revised its projection for 2006 combined earnings for the Utility Group and parent company from between $1.09 per share and $1.22 per share to between $1.57 per share and $1.70 per share as a result of the inclusion of a gain of $0.48 per share in CL&P s third quarter distribution results as a result of a one-time $74 million reduction of income tax expense pursuant to a PLR received from the IRS.

Utility Group Distribution: NU currently projects earnings at its regulated distribution and generation businesses of between $1.23 per share and $1.33 per share, including the reduction in CL&P s income tax expense as a result of the PLR, and between $0.75 per share and $0.85 per share excluding the impact of the PLR. Previously, NU had projected distribution company earnings of $0.89 per share and $0.96 per share in 2006. Among other factors, NU s distribution segments are being negatively affected by less rate relief and lower sales than previously anticipated.

CL&P s distribution rates will remain unchanged except for the previously approved increase of $7 million that will take effect on January 1, 2007. As a result, CL&P does not expect to earn its authorized 9.85 percent ROE in 2007. Management projects that CL&P's ROE could decline to approximately 7 percent. However, management expects to file a rate case in mid-2007, for new rates effective on January 1, 2008.

PSNH's temporary distribution rate increase that took effect on July 1, 2006, and ultimately its permanent rate case is expected to improve PSNH's financial performance in 2007 compared to 2006.

Utility Group Transmission: NU currently projects higher transmission business earnings of between $0.34 per share and $0.37 per share, an increase from the company s previous estimate of between $0.32 per share and $0.35 per share. The increase is due in part to projects being constructed ahead of schedule.

Parent and Other: As a result of higher investment income, a gain on the sale of Globix shares, and earnings from NU's service company and real estate affiliates, NU expects approximately breakeven performance at the parent company as compared with a previously projected loss of $0.09 per share to $0.12 per share.

NU Enterprises: NU is not providing 2006 earnings guidance for NU Enterprises. However, NU expects to record an after-tax gain of approximately $300 million, or approximately $1.95 per share, in the fourth quarter of 2006 related to the sale of competitive generation business.

NU has made significant progress in its strategic initiative to exit all of its competitive businesses. Upon the completion of the recently announced sale of its competitive generation business to ECP, NU will have divested or sold substantially all of NU Enterprises assets. As a result of divestitures, NU s annual revenues are projected to decrease by approximately $2 billion from 2005 levels.

The NU Enterprises assets that have not yet either been sold or placed under contract to be sold are as follows:

- Five wholesale sales contracts in PJM (four of which expire in 2007 and one expires in 2008) and associated purchased supply contracts;
- A long-term wholesale sales contract in New York which expires in 2013;
- Three power purchase contracts (two in New England and one in New York). Two contracts expire in 2007, and one expires in 2012, and
- The electrical contracting company, E. S. Boulos Company (Boulos).

See Note 4, "Assets Held for Sale and Discontinued Operations," for information regarding what businesses are held for sale and discontinued operations.

2007 Outlook: Various securities analysts who follow NU's stock have 2007 earnings estimates in the $1.30 to $1.40 range. The company does not provide specific 2007 guidance until the late fall, but at this time management is comfortable with this range.

There will be several key factors that will impact earnings in 2007. First, investments in the transmission business continue to grow rate base, which in turn provide meaningful net income growth. This factor is supported by the increase in 2006 earnings guidance for the transmission segment.

Second, although there will be no CL&P rate case in 2006, a $7 million rate increase will be in effect for CL&P on January 1, 2007, which is the last increase resulting from CL&P's 2003 rate case. PSNH rate relief and a Yankee Gas rate filing, which the company expects to become effective on July 1, 2007, will also benefit 2007 earnings. The Yankee Gas rate case will incorporate the company s $108 million liquefied natural gas (LNG) facility into rate base and result in a significant increase in Yankee Gas' rate base.

Third, the cash proceeds received from the sale of the competitive generation business will provide interest income for NU parent and offset NU parent's interest and other operating expenses.

Management continues to believe that the company can achieve earnings growth of between 8 percent and 10 percent, and that 2007 earnings growth will be higher than this 8 percent to 10 percent range. Management also believes that this type of growth can support dividend increases above industry averages without negatively impacting the company's dividend payout ratio.

Liquidity

Consolidated: NU continues to maintain an ample level of liquidity. At June 30, 2006, NU's total unused borrowing capacity through its revolving credit agreement, the Utility Group's revolving credit agreement and CL&P's accounts receivable facility totaled approximately $850 million. At June 30, 2006, NU also had $48.7 million of cash and cash equivalents on hand, compared with $45.8 million at December 31, 2005.

Cash flows from operations decreased by $65.3 million from $278.4 million for the first half of 2005 to $213.1 million for the first half of 2006. The decrease in operating cash flows is due primarily to higher regulatory refunds in 2006 as CL&P refunded amounts to its ratepayers to moderate the increase in CL&P's TSO rates that became effective on January 1, 2006. Operating cash flows also decreased due to a higher level of recoverable energy costs paid but not yet recovered in regulated rates. The decrease in operating cash flows is also due to a federal income tax payment of approximately $55 million related to NU's 2005 tax return. This payment was made in the first quarter of 2006. No such federal income tax payment was made in the first quarter of 2005 related to NU's 2004 tax year. Offsetting the decrease in operating cash flows are collections of accounts receivable that were much greater than payments on accounts payable. These changes relate primarily to the termination of wholesale sales obligations and the sale of the retail marketing business. The company expects net cash flows to increase and CL&P refunds to decline in the second half of 2006 as a result of a DPUC decision to terminate a $0.009 per kWh credit on customer bills to refund previous Competitive Transition Assessment (CTA) overrecoveries.

PSNH's operating cash flows are expected to decline in the second half of 2006 and thereafter as a result of a significant reduction in approved SCRC rates to an average rate of $0.0155 per kWh from the current average rate of $0.0335 per kWh effective on July 1, 2006. That decline, which amounts to approximately $170 million annually, is the result of the completion of PSNH's recovery of its Part 3 non-securitized stranded costs as of June 30, 2006.

In November of 2005, NU entered into an amended revolving credit agreement that increased NU s credit line from $500 million to $700 million and extended the maturity date of the agreement by one year to November 6, 2010. There were $111 million of borrowings outstanding under that agreement at June 30, 2006. In November of 2005, NU also entered into a separate liquidity facility. This facility, which was unused, provided $310 million of liquidity and was terminated on June 29, 2006 because of reduced NU Enterprises' liquidity needs.

NU Enterprises had a modestly negative impact on NU's liquidity in the first half of 2006. However, NU Enterprises is expected to have a positive impact on NU's liquidity over the remainder of 2006 assuming the company executes the balance of its plans to exit its remaining competitive businesses. The sale of the retail marketing business, which closed on June 1, 2006, will result in NU making three payments to Hess totaling $44 million. The first of those payments totaling approximately $11.5 million was made on June 1, 2006. The remaining payments of approximately $17.5 million and $15 million are scheduled to be made by December of 2006 and 2007, respectively. Remaining cash flows for the retail marketing business are expected to be positive as accounts receivable of approximately $70 million are collected. Most supply payments through the June 1, 2006 sale date have already been made.

The sale of NU's competitive generation business to ECP will result in significant cash inflows totaling between $500 million and $550 million after assumption of $320 million of debt by ECP and after payment of taxes with proceeds from the sale. The sale of the remaining energy services business is not expected to have a significant impact on NU's liquidity. NU will use these proceeds to fund Utility Group capital expenditures and reduce short-term debt.

Management had previously indicated that the company did not expect to issue additional common equity before 2008. Based on the expected cash inflows totaling between $500 million and $550 million as a result of the sale of the competitive generation business, management currently expects these inflows to largely negate that need, assuming no changes to the company's capital expenditure program or the company's leverage target of 55 percent. However, the divestiture of Select Energy's remaining wholesale contracts could result in significant payments to counterparties or third parties.

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). If NU were to be downgraded to a sub-investment grade level by either Moody's or S&P, a number of Select Energy's contracts would require the posting of additional collateral in the form of cash or letters of credit (LOCs). Were NU's senior unsecured ratings to be reduced to sub-investment grade by either Moody's or S&P, Select Energy could, under its present contracts, be asked to provide approximately $154.3 million of collateral or LOCs to various unaffiliated counterparties and approximately $81 million to several independent system operators and unaffiliated local distribution companies (LDCs) at June 30, 2006. If such a downgrade were to occur, management believes NU would currently be able to provide this collateral.

On August 1, 2006, Moody's downgraded PSNH securities by one notch and changed the outlook to stable from under review - negative. The downgrade resulted from the lower cash flows Moody's forecast for PSNH following PSNH's full recovery of part 3 stranded costs and resulting July 1, 2006 overall rate reduction. At Moody's new rating of Baa1, PSNH bonds continue to be at an investment grade level.

NU paid common dividends of $54 million in the first half of 2006, compared with $41.6 million in the first half of 2005. The higher level of dividend payments reflects a 7.7 percent increase in the NU quarterly dividend to $0.175 per share that was effective with the September 30, 2005 dividend and an increase in the number of outstanding shares as a result of the 23 million common share issuance in December of 2005. On May 9, 2006, the NU Board of Trustees approved a dividend of $0.1875 per share, payable September 29, 2006 to shareholders of record as of September 1, 2006. This represented the sixth consecutive year that NU s Board of Trustees has approved an increase in the quarterly dividend.

Capital expenditures included on the condensed consolidated statements of cash flows and described in the liquidity section of this management's discussion and analysis are cash capital expenditures and do not include cost of removal, the allowance for funds used during construction (AFUDC), and the capitalized portion of pension expense or income. NU's capital expenditures totaled $380.7 million in the first half of 2006, compared with $332.1 million in the first half of 2005. First half 2006 capital expenditures totaled $240 million by CL&P, $60.4 million by PSNH, $20.8 million by WMECO, $34.4 million by Yankee Gas and $25.1 million by other NU subsidiaries, including $10.1 million by NU Enterprises. The increase in NU's capital expenditures was primarily the result of higher transmission capital expenditures, particularly at CL&P. Utility Group capital expenditures are expected to approach approximately $900 million in 2006, including approximately $600 million, $150 million, $50 million, and $100 million for CL&P, PSNH, WMECO and Yankee Gas, respectively.

On April 6, 2006, Mode 1 Communications, Inc., a wholly-owned subsidiary of NU, sold its entire investment in 2.7 million Globix shares for $6.7 million and recognized an after-tax gain of $2 million.

Utility Group: In November of 2005, the Utility Group companies entered into an amended revolving credit agreement that maintained its $400 million credit line and extended the maturity date of their agreement by one year to November 6, 2010. There were $20 million of borrowings outstanding under that agreement at June 30, 2006.

In addition to its revolving credit line, 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, 2006, CL&P had sold $100 million to that financial institution. For more information regarding the sale of receivables, see Note 1F, "Summary of Significant Accounting Policies - Sale of Customer Receivables," to the condensed consolidated financial statements.

NU expects to fund approximately half of its expected capital expenditures over the next several years through internally generated cash flows. As a result, the company expects its Utility Group companies, particularly CL&P, to issue debt regularly. On June 7, 2006, CL&P closed on the sale of $250 million of 30-year first mortgage bonds with a coupon rate of 6.35 percent. Because of an interest rate hedge CL&P executed earlier in 2006 to offset the impact of higher interest rates, CL&P received $7.8 million from counterparties at the closing of this transaction.

On June 21, 2006, PSNH converted $89.3 million variable interest rate insured tax-exempt pollution control revenue bonds to a fixed interest rate of 4.75 percent with maturity in 2021.

The Utility Group will also fund its capital expenditures through equity contributions from NU. In the first half of 2006, NU invested $60 million of equity into CL&P, $2.5 million into PSNH, $20.5 million into WMECO and $30 million into Yankee Gas.

NU Enterprises: Currently, NU Enterprises' liquidity is impacted by both the amount of collateral it receives from other counterparties and the amount of collateral it is required to deposit with counterparties. From December 31, 2005 to June 30, 2006, the net positive impact on NU Enterprises' liquidity related to these items was approximately $75 million.

Most of the working capital and LOCs required by NU Enterprises are currently used to support the wholesale marketing business. As NU Enterprises' wholesale contracts expire or are exited, its liquidity requirements are expected to decline. However, the sale or assignment of additional long-term below market wholesale power contracts would likely require NU Enterprises to continue to make significant payments to the counterparties in such transactions.

NU Enterprises Divestitures

In 2005, NU announced that NU Enterprises would exit its competitive businesses. NU will use sale proceeds to invest in its regulated businesses, reduce short-term debt and pay taxes related to the sale of the competitive operation business. An overview of this process is as follows:

Wholesale Marketing Business: In the first half of 2006, NU Enterprises continued to serve its remaining wholesale power obligations. Select Energy's remaining wholesale obligations in the PJM power pool include 5 wholesale sales contracts and numerous supply contracts which expire by 2008. By the end of 2006, if no obligations are divested, remaining obligations in PJM are projected to be approximately 4 million MWh, down from 16 million MWh as of March of 2005 when NU Enterprises announced it was exiting the wholesale marketing business. Select Energy's one remaining wholesale sales contract in New York expires in 2013. NU Enterprises also has three contracts to purchase generation products, two of which expire in 2007, with the remaining contract expiring in 2012.

NU Enterprises resumed efforts to reduce its obligations related to its portfolio of PJM sales and supply contracts. At this time, management cannot estimate at what value the contracts will be divested compared to the mark-to-market currently recorded.

Select Energy has also taken steps to reduce the volatility of these obligations by hedging a portion of them. Management is continuing to pursue opportunities to complete the divestiture of the wholesale marketing business and began to market these contracts in July of 2006.

Retail Marketing Business: On June 1, 2006, Select Energy sold its retail marketing business to Hess, including all of its retail sales obligations and supply contracts. Under the terms of the agreement, Select Energy paid Hess approximately $11.5 million at closing and will pay an additional $32.5 million included in other current liabilities on the accompanying condensed consolidated balance sheet by the end of 2007.

NU Enterprises continues to have accounts receivable of approximately $70 million at June 30, 2006, for services provided to customers prior to the June 1, 2006 sale of the retail marketing business. The company will monitor the collectibility of the accounts receivable retained to ensure their carrying values continue to be realizable.

In connection with the sale of the retail marketing business, NU has provided various indemnifications to Hess. Management does not expect that these indemnification obligations will have a material adverse effect on NU, and no liability has been recorded at June 30, 2006. See Note 7G, "Guarantees and Indemnifications," for further information regarding these indemnifications.

Competitive Generation Business: On July 24, 2006, NU reached an agreement with ECP to sell its 100 percent ownership in NGC and HWP's 146-MW Mt. Tom for $1.34 billion, including the assumption of $320 million of NGC debt. The sale of the NGC stock and the Mt. Tom plant requires FERC approval and other approvals. The sale is expected to close by the end of 2006. Exclusive of income tax reserve, apportionment and other secondary impacts, NU currently expects to record an after-tax gain of approximately $300 million upon completion of the sale.

Energy Services Businesses: SECI-NH, including Reeds Ferry, and Woods Network were sold in November of 2005. In January of 2006, the Massachusetts service location of SECI-CT was sold. In April of 2006, NU Enterprises sold certain assets of Woods Electrical.

On May 5, 2006, NU Enterprises completed the sale of SESI to Ameresco. In connection with the closing of this transaction, NU Enterprises paid Ameresco approximately $7.7 million and recorded a pre-tax charge to income of $5.6 million in the second quarter of 2006, which is included in loss from sale of discontinued operations on the accompanying condensed consolidated statements of income/(loss).

At June 30, 2006, $16 million in total assets and $10.8 million in total liabilities of SECI-NH, Woods Network, Woods Electrical and SESI were retained by NU Enterprises after the sale of these businesses. These assets and liabilities are primarily comprised of accounts receivable and unbilled revenues, accounts payable, long-term and short-term debt. The company will monitor the collectibility of the accounts receivable retained to ensure their carrying values continue to be realizable.

NU Enterprises continues to wind down eight SECI-CT contracts and anticipates their completion by the end of 2006. NU Enterprises continues to own and operate Boulos.

NU guarantees SESI's performance under government contracts financed by one investor. NU is permitted to and intends to terminate these guarantees prior to their annual anniversary dates over the next nine months. Upon notice of non-renewal, the investor can require NU to repurchase the underlying contract payments to satisfy the debt. Ameresco has a commitment from a lender to finance SESI s repurchase of these contract payments from NU. On July 7, 2006, the investor notified SESI that pursuant to financing terms it would require SESI to repurchase contract payments relating to the only guaranteed project that was behind schedule. SESI did not satisfy this requirement and on July 26, 2006, the contract payments were assigned to NU and NU paid the investor $10.4 million, $0.6 million of which will be recorded as a third quarter loss. NU recorded a $0.2 million loss to reflect the fair value of this guarantee in the second quarter. NU expects to sell the contract payments to SESI upon SESI's completion of the project which SESI would finance with its committed lender. NU may record additional losses associated with this transaction and associated with the planned termination of its other SESI guarantees, the amount of which will depend on the final calculation of contract payment purchase amounts, changes in interest rates used to determine Ameresco s financing proceeds, the amount of project cash available to offset NU s costs, and other factors.

Provisions of the purchase agreement also require NU to indemnify Ameresco for estimated costs to complete or modify specific construction projects above specified levels. Management does not expect that these indemnifications obligations will have a material adverse effect on NU.

See Note 7G, "Guarantees and Indemnifications," for further information regarding these guarantees.

Business Development and Capital Expenditures

Consolidated: In the first half of 2006, NU's cash capital expenditures, which exclude cost of removal, AFUDC, and the capitalized portion of pension expense or income, totaled $380.7 million, compared with $332.1 million in the first half of 2005. Capital expenditures including cost of removal, AFUDC, and the capitalized portion of pension expense or income totaled $420.3 million in the first half of 2006, compared with $344.3 million in 2005. Included in these amounts are $399.2 million and $331.2 million related to the Utility Group. Capital expenditures are expected to total approximately $900 million in 2006, compared with $813.4 million in 2005. This increasing level of capital expenditures is caused primarily by the continuing need to improve the capacity and reliability of NU's regulated transmission system.

Utility Group:

Transmission Rate Base: At December 31, 2005, the Utility Group's transmission business rate base was approximately $600 million and is projected to be approximately $1.0 billion at December 31, 2006. Several factors may impact the December 31, 2006 projected Utility Group transmission business rate base amount, including the level and timing of transmission capital expenditures, transmission plant placed in service, and various other factors.

CL&P: In December of 2003, the DPUC approved a total of $900 million of distribution capital expenditures for CL&P from 2004 through 2007. Those expenditures are intended to improve the reliability of the distribution system and to meet growth requirements on the distribution system. In the first half of 2006, CL&P's distribution capital expenditures totaled $100.7 million, compared with $125.9 million in the first half of 2005. In 2006, CL&P projects distribution capital expenditures of approximately $200 million.

CL&P's transmission capital expenditures totaled $176.9 million in the first half of 2006, compared with $66 million in the first half of 2005. The increase was primarily the result of increased spending on a new 21-mile 345 kilovolt (kV) transmission project between Bethel and Norwalk, Connecticut. In 2006, CL&P's transmission capital expenditures are projected to total approximately $400 million.

Transmission capital expenditures in Connecticut are focused primarily on four major transmission projects in southwest Connecticut. These projects include 1) the Bethel to Norwalk project, 2) a 69-mile Middletown to Norwalk 345 kV transmission project, 3) a related two cable 115 kV underground project between Norwalk and Stamford, Connecticut (Glenbrook Cables), and 4) the replacement of the existing 138 kV cable between Connecticut and Long Island. Each of these projects has received approval from the Connecticut Siting Council (CSC) and ISO-NE. Capital expenditures for these projects totaled $142.4 million in the first half of 2006 compared to $40.6 million in the first half of 2005.

Construction began in April of 2005 on a 21-mile 115 kV/345 kV line project between Bethel and Norwalk. This project, which is expected to cost approximately $350 million, is approximately 90 percent complete and is expected to be placed in service by November of 2006. CL&P has capitalized $289.7 million through June 30, 2006.

On April 7, 2005, the CSC unanimously approved a proposal by CL&P and United Illuminating to build a 69-mile 345 kV transmission line from Middletown to Norwalk and CL&P has commenced site work. Approximately 24 miles of the 345 kV line will be built underground with the balance being built overhead. The project still requires CSC review of certain detailed construction plans, as well as United States Army Corps of Engineers approval to bury the line beneath certain navigable rivers and the Connecticut Department of Environmental Protection (DEP) approvals. The original CSC decision included provisions for low magnetic field designs in certain areas and made variations to the proposed route. The CSC intends to amend the Middletown to Norwalk docket and will hold a limited scope proceeding to address CL&P's proposal to re-route a 1.3 mile section of 345 kV underground cable in Norwalk. This route change will further minimize the environmental impact of the project and is not expected to change either its cost or scope. CL&P received final technical approval from ISO-NE on January 20, 2006 and expects to award the major equipment contracts during 2006. CL&P's portion of the project is estimated to cost approximately $1.05 billion and is expected to be completed by the end of 2009. CL&P has reached tentative settlement agreements on all three of the appeals related to the project, and signed two settlement agreements. At this time, CL&P does not expect any of these three appeals to delay construction. At June 30, 2006, CL&P has capitalized $81.4 million associated with this project.

CL&P s construction of the Glenbrook Cables Project, two 9-mile 115 kV underground transmission lines between Norwalk and Stamford, was approved by the CSC on July 20, 2005 and approved by ISO-NE on August 3, 2005. This decision has not been appealed. The project is intended to respond to the growing electric demand in the area. The original, conceptual cost estimate of $120 million has been increased to $183 million, reflecting actual construction and procurement experience on the Middletown to Norwalk and Bethel to Norwalk projects. Management expects to begin construction in late 2006 and expects the lines to be in service in 2008. Through June 30, 2006, CL&P has capitalized $13.5 million associated with this project.

On October 1, 2004, CL&P and the Long Island Power Authority (LIPA) jointly filed plans with the DEP to replace a 138 kV undersea electric transmission line between Norwalk, Connecticut and Northport - Long Island, New York, consistent with a comprehensive settlement agreement reached on June 24, 2004. CL&P and LIPA each own approximately 50 percent of the line. CL&P's portion of the project is estimated to cost $72 million. On June 20, 2005, the New York State Controller s Officer and the New York State Attorney General approved the comprehensive settlement agreement. The project had earlier received CSC approval. State and federal permits are expected to be issued in the third quarter of 2006. In June of 2006, CL&P awarded the engineering, procurement and construction contract for this project and expects to place the project into service in 2008. Through June 30, 2006, CL&P has capitalized $6.6 million associated with this project.

In the fourth quarter of 2005, CL&P began construction of a new substation in Killingly, Connecticut, which will improve CL&P s 345 kV and 115 kV transmission systems in northeast Connecticut. The project is expected to be completed by the end of 2006 at a cost of approximately $32 million. At June 30, 2006, CL&P has capitalized $13.9 million associated with this project.

As part of a larger regional system plan, NU, ISO-NE and National Grid have begun planning an upgrade to the transmission system connecting Massachusetts, Rhode Island and Connecticut in a comprehensive study called the Southern New England Transmission Reliability Project. The parties are expected to identify a number of possible routes and configurations by 2007. NU and National Grid have not yet completed a detailed estimate of the total cost for the upgrade, but NU estimates that approximately $400 million of its $2.3 billion transmission capital budget in 2006 through 2010 could be spent on this project.

Yankee Gas: In the first half of 2006, Yankee Gas' capital expenditures totaled $37.6 million, compared with $32.2 million in the first half of 2005. Yankee Gas is constructing a LNG storage and production facility in Waterbury, Connecticut, which will be capable of storing the equivalent of 1.2 billion cubic feet of natural gas. Construction of the facility began in March of 2005 and is expected to be completed in time for the 2007/2008 heating season. The facility, which is expected to cost $108 million, was approximately 65 percent complete at June 30, 2006. Yankee Gas has capitalized $67.1 million related to this project through June 30, 2006.

PSNH: In the first half of 2006, PSNH's capital expenditures totaled $63.8 million, compared with $86.2 million in the first half of 2005. The 2006 expenditures included $6.3 million in construction activities associated with PSNH's conversion of a 50 MW coal-fired unit at Schiller Station in Portsmouth, New Hampshire to burn wood (Northern Wood Power Project). Construction of the $75 million Northern Wood Power Project started in 2004 and the project is expected to be declared commercially operational in the fall of 2006. The new unit generated its first test power when it was phased to the transmission grid on July 4, 2006. The unit is currently undergoing a number of start-up and testing activities. Through June 30, 2006, PSNH has capitalized $70.9 million related to this project and the project was 95 percent complete.

WMECO: WMECO's capital expenditures totaled $20.2 million in the first half of 2006, compared with $20.9 million in the first half of 2005. In 2006, WMECO projects total capital expenditures of approximately $50 million.

NU Enterprises: In the second quarter of 2006, HWP completed installation of a selective catalytic reduction system at Mt. Tom. The $14 million project commenced in July of 2005 and began operation in June of 2006. At June 30, 2006, HWP has capitalized $13.7 million related to this project.

Transmission Access and FERC Regulatory Changes

The New England Regional Transmission Organization (RTO) was activated on February 1, 2005. As a result, the ROE in the local network service (LNS) tariff was increased to 12.8 percent. The ROE being utilized in the calculation of the current regional network service (RNS) rates is the sum of the 12.8 percent "base" ROE, plus a 50 basis point incentive adder for joining the RTO, or a total of 13.3 percent, plus an additional 100 basis point adder on new transmission investment. NU collects approximately 75 percent of its wholesale transmission revenues under its RNS tariff and 25 percent under its LNS tariff.

An initial decision by a FERC administrative law judge (ALJ) set the base ROE at 10.72 percent as compared with the 12.8 percent requested by the New England RTO. One of the adjustments made by the ALJ was to modify the underlying proxy group used to determine the ROE, resulting in a reduction in the base ROE of approximately 50 basis points. The ALJ deferred to the FERC for final resolution on the 100 basis point incentive adder for new transmission investments but reaffirmed the 50 basis point incentive for joining the RTO. The New England transmission owners have challenged the ALJ's findings and recommendations through written exceptions filed on June 27, 2005. The result of this order, if upheld by the FERC, would be an ROE for LNS of 10.72 percent and an ROE for RNS of 11.22 percent. When blended, the resulting "all in" ROE would be approximately 11.15 percent for the NU

transmission business. A final order from the FERC is expected in 2006. Management cannot at this time predict what ROE will ultimately be established by the FERC in these proceedings but for purposes of current earnings accruals and estimates, the transmission business is assuming an ROE of 11.5 percent. As a result of the difference in the 12.8 percent ROE and the 13.3 percent ROE being billed to LNS and RNS customers, respectively, and the 11.5 percent ROE assumed for earnings accruals and estimates,
at June 30, 2006, a $10.5 million regulatory liability was recognized.

On July 20, 2006, the FERC issued final rules promoting transmission investment through pricing reform that included up to 100 percent of construction work in progress (CWIP), accelerated depreciation, higher ROEs for belonging to an RTO, among others. The final rule identifies specific incentives the FERC will allow when justified in the context of specific rate applications. The burden remains on the applicant to illustrate through its filing that the incentives requested are just and reasonable and the project involved increases reliability or decreases congestion costs. Management views this rule to be positive, but the actual impacts on NU will be determined by the specific incentives that NU seeks and that are approved by the FERC.

Legislative Matters

Environmental Legislation: The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by certain northeastern states to develop a regional program for stabilizing and ultimately reducing CO_2 emissions from fossil-fired electric generators. This initiative proposed to stabilize CO_2 emissions at current levels and require a ten percent reduction by 2020. The RGGI agreement was signed on December 20, 2005 by the states of Connecticut, Delaware, Maine, New Jersey, New Hampshire, New York, and Vermont. Each state commits to propose for approval legislative and regulatory mechanisms to implement the program. RGGI may impact PSNH's Merrimack, Newington and Schiller stations, if adopted by the New Hampshire legislature. At this time, the impact of this agreement on NU cannot be determined.

On January 1, 2006 a CO_2 cap on emissions from fossil-fired electric generators took effect in Massachusetts, with a separate CO_2 emissions rate limit effective in 2008. Affected parties are currently awaiting the Massachusetts DEP's proposal concerning a trading or other form of offset program. The Mt. Tom plant would be impacted by this regulation. Given the uncertainty of the future compliance mechanism under these regulations, the impact of this regulation on NU and the Mt. Tom plant cannot be determined.

Connecticut:

Transmission Tracking Mechanism: On July 6, 2005, Connecticut adopted legislation creating a mechanism to allow the DPUC to true-up, at least annually, the retail transmission charge in local electric distribution company rates based on changes in FERC-approved charges. This mechanism, which includes two adjustments annually in January and June, allows CL&P to include forward-looking transmission charges in its retail transmission rate and promptly recover its transmission expenditures. On January 1, 2006, CL&P raised its retail transmission rate to collect $21 million of additional transmission costs over the first half of 2006. On July 1, 2006, CL&P raised its retail transmission rate to collect an incremental $6.1 million of additional revenues over the second half of 2006.

Public Act 05-01: Public Act 05-01, an "Act Concerning Energy Independence," (Act) was signed by Governor Rell on July 22, 2005. The legislation provides incentives to encourage the construction of distributed generation, new large-scale generation, and conservation and load management initiatives to reduce federally mandated congestion cost (FMCC) charges. The legislation requires regulators to a) implement near-term measures as soon as possible, and b) commence a new request for proposals to build customer side distributed resources and contracts for new or repowered larger generating facilities in the state. Developers could receive contracts of up to 15 years from Connecticut distribution companies. The legislation provides utilities with the opportunity to earn one-time awards for generation that is installed in their service territories. The legislation requires the DPUC to investigate the financial impact on distribution companies of entering into long-term contracts and to allow distribution companies to recover through rates any increased costs. The DPUC ruled that at this point the financial impact of any such contracts is hypothetical and instructed the utilities to raise the issue in subsequent rate cases. CL&P has appealed this decision. The DPUC is conducting additional proceedings to implement this legislation.

On March 27, 2006, the DPUC issued final decisions that will provide customers with financial incentives for installing distributed generation resources. These customer incentives include capital grants of up to $200 per kW for emergency generators and $450 per kW for base load generation, with an extra customer incentive of $50 per kW for projects located in southwest Connecticut. Distribution companies, including CL&P, could be eligible for one-time awards of $200 per kW for customer demand-side generation and $25 per kW for more traditional generation when these units become operational.

New Hampshire:

Environmental Legislation: In April of 2006, New Hampshire adopted legislation requiring PSNH to reduce the level of mercury emissions from its coal-fired plants by 2013 with incentives for early reductions. To comply with the legislation PSNH intends to install wet scrubber technology by mid-2013 at its two Merrimack coal units, which combined generate 433 MW. PSNH currently estimates the cost to comply with this law to be approximately $250 million. However, this amount is subject to change as final design of the project is undertaken. State law and PSNH's restructuring agreement provide for the recovery of its generation costs, including the cost to comply with state environmental regulations. The company does not expect these costs to have a significant impact as sulfur emissions are expected to be reduced by at least 80 percent with a corresponding reduction in the need to purchase sulfur allowances.

<u>Utility Group Regulatory Issues and Rate Matters</u>

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 through a combination of the RNS tariff and NU's LNS tariff. NU's LNS rate is reset on January 1 and June 1 of each year. NU's RNS rate is reset on June 1 of each year. Additionally, NU's LNS tariff provides for a true-up to actual costs, which ensures that NU's transmission business recovers its total transmission revenue requirements, including the allowed ROE.

Effective February 1, 2006, NU included 50 percent of CWIP for its four major southwest Connecticut transmission projects in its formula rate for transmission service (Schedule 21 NU (LNS)). The new rates allow NU to collect 50 percent of the construction financing expenses while these projects are under construction.

On July 28, 2006, the FERC approved NU's proposal to allocate costs associated with the Bethel to Norwalk transmission project that are determined to be localized costs to all customers in Connecticut as all of Connecticut will benefit from the associated reduction in congestion charges. There are three load serving entities in Connecticut: CL&P, The United Illuminating Company and the Connecticut Municipal Electrical Energy Cooperative (CMEEC). These customers would pay their allocated share of the localized costs on a projected basis commencing June 1, 2006, subject to true-up based on actual costs. For the balance of 2006, these charges would include each customer s allocated share of NU s transmission revenue requirement from the time the localized facilities were first placed in service through May 31, 2006, in addition to the revenue requirements for the remainder of the year.

On June 15, 2006, ISO-NE issued its draft decision on CL&P s transmission cost allocation (TCA) application for the Bethel to Norwalk project and approximately $7 million of ancillary projects. ISO-NE approved $237.3 million for regional cost recovery and found that the remaining $119.9 million are costs that should be localized. On July 14, 2006, NU submitted its comments to ISO-NE on their draft determination of the Bethel-Norwalk project s localized costs. NU is requesting ISO-NE reconsider certain determinations and correct certain factual statements. As specified in Schedule 12C, ISO-NE and NU will now enter into negotiations not to exceed 60 days.

Transmission - Retail Rates: A significant portion of the NU transmission business revenue comes from ISO-NE charges to the distribution businesses of CL&P, PSNH and WMECO. The distribution businesses recover these costs through the retail rates that are charged to their retail customers. In July of 2005, as a result of the enactment of the legislation passed by the Connecticut legislature in 2005, CL&P began tracking its retail transmission revenues and expenses and on January 1, 2006 raised its retail transmission rate to collect $21 million of additional revenues over the first half of 2006. On July 1, 2006, CL&P raised its retail transmission rates by an incremental $6.1 million. WMECO implemented its retail transmission tracker and rate adjustment mechanism in January of 2002 as part of its 2002 rate change filing. PSNH does not currently have a retail transmission rate tracking mechanism, but the company requested such a mechanism in its 2006 energy delivery rate case.

Forward Capacity Market: In March of 2004, ISO-NE proposed at the FERC an administratively determined electric generation capacity pricing mechanism known as LICAP, intended to provide a revenue stream sufficient to maintain existing generation assets and encourage the construction of new generation assets at levels sufficient to serve peak load, plus fixed reserve and contingency margins. After opposition from state regulators, utilities and various Congressional delegations, the FERC ordered settlement negotiations before an ALJ to determine whether there was an acceptable alternative to LICAP. On March 6, 2006, ISO-NE and a broad cross-section of critical stakeholders from around the region, including CL&P, PSNH and Select Energy, filed a comprehensive settlement agreement at the FERC proposing a FCM in place of the previously proposed LICAP mechanism. The settlement agreement provides for a fixed level of compensation to generators from December 1, 2006 through May 31, 2010 without regard to location in New England, and annual forward capacity auctions, beginning in 2008, for the 1-year period ending on May 31, 2011, and annually thereafter. According to preliminary estimates, FCM would require the operating companies to pay approximately the following amounts during the 3½-year transition period: CL&P - $470 million; PSNH - $80 million; and WMECO - $100 million. CL&P, PSNH and WMECO expect to recover these costs from their customers. On June 16, 2006, the FERC accepted the settlement agreement. The settlement agreement is expected to be implemented by December 1, 2006. Several parties have sought rehearing of this issue by the FERC.

Connecticut - CL&P:

Distribution Rates: In its December 2003 rate case decision, the DPUC allowed CL&P to increase distribution rates annually from 2004 through 2007. A $25 million distribution rate increase took effect on January 1, 2005, an additional $11.9 million distribution rate increase took effect on January 1, 2006, and another $7 million distribution rate increase is due to take effect on January 1, 2007.

On August 4, 2006, CL&P notified Governor Rell and the DPUC that it intends to postpone filing a distribution rate case until mid-2007 for rates effective on January 1, 2008.

Procurement Fee Rate Proceedings: CL&P is currently allowed to collect a fixed procurement fee of 0.50 mills per kWh from customers who purchase TSO service through 2006. One mill is equal to one-tenth of a cent. That fee can increase to 0.75 mills per kWh if CL&P outperforms certain regional benchmarks. CL&P submitted to the DPUC its proposed methodology to calculate the variable portion (incentive portion) of the procurement fee. CL&P requested approval of $5.8 million for its 2004 incentive payment. On December 8, 2005, a draft decision was issued in this docket, which accepted the methodology proposed by CL&P and authorized payment of the $5.8 million incentive fee. A final decision, which had been scheduled for December 28, 2005, was delayed by the DPUC and the DPUC re-opened this docket to allow the Connecticut Office of Consumer Counsel (OCC) to submit additional testimony. A new schedule has been established which provides for a final decision in October of 2006. Management continues to believe that recovery of the $5.8 million regulatory asset recorded related to CL&P's 2004 incentive payment, which was reflected in 2005 earnings, is probable. No amounts have been recorded related to the 2005 incentive portion of CL&P's procurement fee.

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

On March 31, 2006, CL&P filed its 2005 CTA and SBC reconciliation with the DPUC, which compares CTA and SBC revenues to revenue requirements. For the year ended December 31, 2005, total CTA revenues exceeded the CTA revenue requirement by $60.1 million. This amount was recorded as a regulatory liability on the accompanying condensed consolidated balance sheets. For the same period, the SBC revenue requirement exceeded SBC revenues by $1.3 million. On July 24, 2006, the DPUC issued a final decision which approved the reconciliation of the CTA and SBC rates for the year 2005.

In CL&P's 2001 CTA and SBC reconciliation, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany tax liability associated with the intercompany sale of generation assets be excluded from the calculation of CTA revenue requirements. This liability is currently included as a reduction in the calculation of CTA revenue requirements. On September 10, 2003, the DPUC issued a final decision denying CL&P s request, and on October 24, 2003, CL&P appealed the DPUC s final decision to the Connecticut Superior Court. On June 20, 2006, the Connecticut Superior Court denied CL&P's appeal.

Income Taxes: In 2000, CL&P requested from the IRS a PLR regarding the treatment of unamortized UITC and EDIT related to generation assets that were sold. On April 18, 2006, the IRS issued a PLR to CL&P regarding the treatment of UITC and EDIT related to generation assets that CL&P has sold. EDIT are temporary differences between book and taxable income that were recorded when the federal statutory tax rate was higher than it is now or when those differences were expected to be resolved. The PLR holds that it would be a violation of tax regulations if the EDIT or UITC is used to reduce customers' rates following the sale of the generation assets. CL&P was ordered by the DPUC to submit the PLR to the DPUC within 10 days of issuance and retain the UITC and EDIT in their existing accounts pending its receipt and review of the PLR.

CL&P's UITC balance is $59 million and EDIT balance is $15 million, totaling $74 million, related to generation assets that have been sold. On July 27, 2006, the DPUC held that the UITC and EDIT amounts were no longer required to be held in their existing accounts. The $74 million balance will be reflected as a reduction of CL&P's third quarter 2006 income tax expense and will increase CL&P's earnings by the same amount.

Standard Electric Service Procurement: On June 21, 2006, the DPUC approved a proposal by CL&P to issue requests for proposal (RFPs) every six months for periods of up to three years to layer the standard electric service full requirements supply contracts to mitigate market volatility for its residential and lower use commercial and industrial customers. Additionally, the DPUC approved the issuance of RFPs for supplier of last resort service for larger commercial and industrial customers every six months. Previously, all of CL&P s residential, commercial and industrial requirements, regardless of customer size, were bid together. The DPUC s decision also provides for enhanced access to the RFP materials, bids and other data during the RFP process. On August 2, 2006, CL&P issued the RFP for 2007 and 2008.

CL&P Rates: On February 1, 2006, CL&P filed with the DPUC its annual FMCC reconciliation filing for the year ended 2005. No change in the current rates was proposed. A final decision is expected in August of 2006.

Porcelain Cutouts: The DPUC initiated a proceeding relating to an incident involving the failure of certain porcelain cutouts that are used in CL&P's distribution system. A cutout is a protective device that stops the flow of electricity if there is a surge. On April 26, 2006, the DPUC issued an order requiring CL&P to report its progress in replacing porcelain cutouts. As a result of a requirement to remove the porcelain cutouts, an asset retirement obligation (ARO) has been recorded. At June 30, 2006, the fair value of the ARO asset recorded is $4.7 million, accumulated depreciation is $0.6 million, and the ARO liability is $4.7 million. The charge to record the $0.6 million of accumulated depreciation was recorded as a regulatory asset, as management believes that this amount is recoverable in rates. Removal of these assets is expected to occur over three years beginning in 2006.

Connecticut - Yankee Gas:

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' PGA accounting methods and deferred any conclusion on the $9 million of previously recovered revenues until the completion of the audit. Management believes the unbilled sales and revenue adjustments and resultant charges to customers through the PGA clause were appropriate. Based on the facts of the case and the supplemental information provided to the DPUC, management believes the appropriateness of the PGA charges to customers for the time period under review will be approved.

New Hampshire:

DS, SCRC and ES Rates: On January 20, 2006, the NHPUC approved a PSNH request to move reconciliation of its generation costs and revenues (including the prudency of its generation operations) from the SCRC to ES proceedings. The change was effective on February 1, 2006.

On May 1, 2006, PSNH filed its 2005 SCRC reconciliation with the NHPUC, and proceedings have begun. While management believes that the operation of the generation business segment has been prudent and consistent with industry practices, it is unable to determine the impact, if any, of the NHPUC s review of the SCRC on PSNH s earnings or financial position.

On May 30, 2006, PSNH filed with the NHPUC to increase its DS rate by approximately $50 million, to decrease its SCRC to recognize the full recovery of its non-securitized part 3 stranded costs, and to decrease its ES rate to recognize changes in its power supply costs. On June 29, 2006, the NHPUC approved a temporary DS rate increase of $24.5 million, the requested decrease in the SCRC and a decrease in the ES rate. All rate changes were effective on July 1, 2006. The impact of the combined rate changes is an overall decrease of 15.5 percent. The temporary DS rate increase will be reconciled to the NHPUC decision in a full rate case to be decided in 2007, effective back to July 1, 2006.

Coal Procurement Docket: During the second quarter of 2006, the NHPUC opened a docket to review PSNH's coal procurement and coal transportation policies and procedures. PSNH is currently responding to data requests from the NHPUC's outside consultant. While management believes its coal procurement and transportation policies and procedures are prudent and consistent with industry practice, it is unable to determine the impact, if any, of the NHPUC's review on PSNH's earnings or financial position.

Generation ROE: On December 2, 2005 the NHPUC issued a decision lowering PSNH s allowed ROE to 9.62 percent that was retroactive to an effective date of August 1, 2005 and PSNH's request for reconsideration was denied. On May 17, 2006, the New Hampshire Supreme Court declined to consider PSNH s appeal of the NHPUC's decision. This decrease in allowed ROE will lower PSNH s net income by approximately $1.5 million annually based on the current level of generation asset investment.

Massachusetts:

Transition Cost Reconciliation: WMECO filed its 2005 transition cost reconciliation with the Massachusetts Department of Telecommunications and Energy (DTE) on March 31, 2006. This filing reconciles transition costs, default service costs and retail transmission costs with their associated revenues collected from customers. The DTE has not yet reviewed this filing or issued a schedule for review. Therefore the timing of a decision is uncertain at this time. Management does not expect the outcome of the DTE's review to have a material adverse impact on WMECO's earnings or financial position.

Annual Rate Change Filing: Under the 2004 rate case settlement agreement, WMECO expects to file later in 2006 for new rates to be effective on January 1, 2007. Pursuant to its 2004 rate settlement, WMECO was allowed to file for a rate increase in June of 2006 to take effect on January 1, 2007. WMECO has delayed its rate filing in order to pursue settlement discussions with several parties, traditionally involved in WMECO rate cases. WMECO is hopeful these discussions will lead to a settlement satisfactory to the company and that the DTE will approve the settlement for new rates effective on January 1, 2007.

Deferred Contractual Obligations

CYAPC: On July 1, 2004, the Connecticut Yankee Atomic Power Company (CYAPC) filed with the FERC for recovery seeking to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning on January 1, 2005. On August 30, 2004, the FERC issued an order accepting the rates, with collection by CYAPC beginning on February 1, 2005, subject to refund.

The FERC staff filed testimony that recommended a total $38 million decrease in the requested rate increase, claiming that CYAPC should have used a different gross domestic product (GDP) escalator. NU's share of this recommended decrease is $18.6 million.

On November 22, 2005, a FERC administrative law judge issued an initial decision finding no imprudence on CYAPC's part. However, the administrative law judge did agree with the FERC staff s position that a lower GDP escalator should be used for calculating the rate increase and found that CYAPC should recalculate its decommissioning charges to reflect the lower escalator. Management expects that if the FERC staff's position on the decommissioning GDP cost escalator is found by the FERC to be more appropriate than that used by CYAPC to develop its proposed rates, then CYAPC would review whether to reduce its estimated decommissioning obligation and reduce its customers' obligations, including the obligation of CL&P, PSNH and WMECO.

The company believes that the costs have been prudently incurred and will ultimately be recovered from the customers of CL&P, PSNH and WMECO. However, there is a risk that some portion of these increased costs may not be recovered, or will have to be refunded if recovered, as a result of the FERC proceedings.

On June 10, 2004, the DPUC and the OCC filed a petition with the FERC seeking a declaratory order that CYAPC be allowed to recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but that such purchasers may not be allowed to recover in their retail rates any costs that the FERC might determine to have been imprudently incurred. The FERC rejected the DPUC's and OCC's petition, whereupon the DPUC filed an appeal of the FERC's decision with the D.C. Circuit Court of Appeals. The FERC and CYAPC have asked the court to dismiss the case, and the DPUC has objected to a dismissal. On June 13, 2006, the court decided not to take up the motion to dismiss until it reviews the case on the merits. A briefing schedule has not yet been set.

Parties to these proceedings are currently engaged in active settlement discussions, the outcome of which management cannot determine at this time.

YAEC: In November of 2005, YAEC established an updated estimate of the cost of completing the decommissioning of its plant. On January 31, 2006, the FERC issued an order accepting the rate increase, effective February 1, 2006, subject to refund by YAEC after hearings and settlement judge proceedings.

On May 1, 2006, YAEC filed with the FERC a settlement agreement with the DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service. Under the settlement agreement, YAEC agreed to revise its November 2005 decommissioning cost increase from $85 million to $79 million. The revision includes adjustments for contingencies and projected escalation and certain decontamination and dismantlement (D&D) expenses. Other terms of the settlement agreement include extending the collection period for charges through December 2014, reconciling and adjusting future charges based on actual D&D expenses and the decommissioning trust fund's actual investment earnings. The company believes that its share of the increase in decommissioning costs will ultimately be recovered from the customers of CL&P, PSNH and WMECO. NU has a 38.5 percent ownership interest in YAEC. On July 31, 2006, the FERC approved the settlement agreement which then became effective and will not materially affect the level of 2006 charges.

MYAPC: MYAPC is collecting amounts in rates that are adequate to recover the remaining cost of decommissioning its plant.

Spent Nuclear Fuel Litigation: CYAPC, YAEC and MYAPC commenced litigation in 1998 charging that the federal government breached contracts it entered into with each company in 1983 under the Nuclear Waste Policy Act of 1982. The trial ended on August 1, 2004, and a verdict has not been reached. Post-trial findings of facts and final briefs were filed by the parties in January of 2005. The Yankee Companies' current rates do not include an amount for recovery of damages in this matter. Management can predict neither the outcome of this matter nor its ultimate impact on NU.

NU Enterprises

NU has decided to exit all aspects of NU Enterprises' businesses.

Merchant Energy Business: At June 30, 2006, the merchant energy business includes Select Energy's wholesale marketing business, 1,442 MW of generation assets, including 1,296 MW of primarily pumped storage and hydroelectric generation assets at NGC and 146 MW of coal-fired generation assets at HWP related to Mt. Tom, and NGS, which NU Enterprises is exiting. Prior to the March 2005 decision to exit the wholesale marketing business, this business also included full requirements sales to LDCs and bilateral sales to other load-serving counterparties. These sales were sourced by the generation assets and an inventory of energy contracts.

Energy Services Business: At June 30, 2006, the energy services businesses include the operations of Boulos, which is not currently being actively marketed, and SECI-CT, which is a division of SECI.

Intercompany Transactions: There were no CL&P TSO purchases from Select Energy in the second quarters of 2006 or 2005. Other energy purchases between CL&P and Select Energy totaled $7.1 million in the first half of 2006 and $26.7 million in the first half of 2005. WMECO had $1 million in purchases from Select Energy in the first half of 2006, compared with $37.9 million in the first half of 2005. These transactions relate to nontraditional standard offer contracts.

Select Energy purchases from NGC and Mt. Tom represented $48.3 million and $98.1 million for the six months ended June 30, 2006, respectively. These amounts totaled $52.1 million and $105 million for NGC and Mt. Tom, respectively, for the six months ended June 30, 2005.

Risk Management: Until the exit from the merchant energy business is completed, NU Enterprises will continue to be exposed to various market risks which could negatively affect the value of its remaining business. This business includes its remaining portfolio of wholesale energy contracts and its generation assets. Market risk at this point is comprised of the possibility of adverse energy commodity price movements and, in the case of the wholesale marketing business, unexpected load ingress or egress, which would affect the volumes and values of these contracts.

NU Enterprises manages these and associated operating risks through detailed operating procedures and an internal review committee. A separate, parent-level committee, the Risk Oversight Council (ROC), meets monthly and upon the occurrence of specific portfolio-triggered events with NU Enterprises' leadership to review the conformity of NU

Enterprises' activities, commitments and exposures to NU's risk parameters.

Wholesale Contracts: As a result of NU s decision to exit the wholesale marketing business, certain wholesale energy contracts previously accounted for under accrual accounting were required to be marked-to-market in the first quarter of 2005. Existing energy trading contracts have been and will continue to be marked-to-market with changes in fair value reflected in the statements of income/(loss).

At June 30, 2006 and December 31, 2005, Select Energy had wholesale derivative assets and derivative liabilities as follows:

(Millions of Dollars)	**June 30, 2006**	**December 31, 2005**
Current wholesale derivative assets	$ 103.1	$ 256.6
Long-term wholesale derivative assets	52.9	103.5
Current wholesale derivative liabilities	(174.2)	(369.3)
Long-term wholesale derivative liabilities	(137.5)	(220.9)
Portfolio	$(155.7)	$(230.1)

NU Enterprises resumed efforts to reduce its obligations related to its portfolio of PJM sales and supply contracts. NU Enterprises also has three contracts to purchase generation products, two of which expire in 2007, with the remaining contract expiring in 2012.

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

Select Energy has policies and procedures requiring all wholesale positions to be marked-to-market at the end of each business day and segregating responsibilities between the individuals actually transacting (front office) and those confirming the trades (middle office). The determination of the portfolio's fair value is the responsibility of the middle office independent from the front office.

The methods used to determine the fair value of wholesale energy contracts are identified and segregated in the table of fair value of contracts at June 30, 2006 and December 31, 2005. A description of each method is as follows: 1) prices actively quoted primarily

represent New York Mercantile Exchange (NYMEX) futures, swaps and options 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 or natural gas, 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 has a contract for which a portion of the contract's fair value is determined based on a model or other valuation method. The model utilizes natural gas prices and a conversion factor to electricity. Broker quotes for electricity at locations for which Select Energy has entered into transactions are generally available through the year 2009. For all natural gas positions, broker quotes extend through 2011 and are approximated for 2012 and 2013.

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.

As of June 30, 2006 and December 31, 2005, the sources of the fair value of wholesale contracts and for the three and six months ended June 30, 2006 and 2005, the changes in fair value of these contracts are included in the following tables:

(Millions of Dollars)	**Fair Value of Wholesale Contracts at June 30, 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	$ 11.1	$ 2.7	$ -	$ 13.8
Prices provided by external sources	(82.2)	(47.1)	(1.2)	(130.5)
Models based	-	(16.5)	(22.5)	(39.0)
Totals	$(71.1)	$(60.9)	$(23.7)	$(155.7)

(Millions of Dollars)	**Fair Value of Wholesale Contracts at December 31, 2005**			
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	$ 31.3	$ 19.1	$ -	$ 50.4
Prices provided by external sources	(147.5)	(94.7)	(2.8)	(245.0)

Models based	0.7	(10.3)	(25.9)	(35.5)
Totals	$(115.5)	$(85.9)	$(28.7)	$(230.1)

	Three Months Ended June 30, 2006	**Six Months Ended June 30, 2006**
	Total Portfolio Fair Value	**Total Portfolio Fair Value**
Fair value of wholesale contracts outstanding at beginning of period	$(173.7)	$(230.1)
Contracts realized or otherwise settled during the period	30.0	93.4
Changes in fair value recorded:		
Wholesale contract market changes, net	(11.9)	(18.7)
Fuel, purchased and net interchange power	(0.1)	(0.2)
Operating revenues	-	(0.1)
Changes in model based assumption included in operating revenues	-	-
Fair value of wholesale contracts outstanding at end of period	$(155.7)	$(155.7)

Changes in the fair value of wholesale contracts that were marked-to-market as a result of the decision to exit the wholesale business totaled a negative $11.9 million and $18.7 million for the three and six months ended June 30, 2006, respectively, and are recorded as wholesale contract market changes, net on the accompanying condensed consolidated statements of income/(loss). Changes in the fair value of natural gas contracts totaling a negative $0.1 million and $0.2 million for the three and six months ended June 30, 2006, respectively, are recorded as fuel, purchased and net interchange power, while changes in fair value of contracts formerly designated as trading totaling a negative $0.1 million for the six months ended June 30, 2006, respectively, are recorded as revenue on the condensed consolidated statements of income/(loss).

Retail Marketing Activities: Select Energy sold its retail marketing business to Hess on June 1, 2006.

At June 30, 2006, Select Energy had derivative assets and liabilities totaling $5.3 million and $4.3 million, respectively, related to back-to-back agreements for electric and gas contracts that Select Energy has not yet received consent from the customers to transfer to Hess. These derivative assets and liabilities are classified as assets held for sale and liabilities of assets held for sale, respectively, on the accompanying condensed consolidated balance sheets.

At June 30, 2006 and December 31, 2005, Select Energy had retail derivative assets and derivative liabilities as follows:

(Millions of Dollars)	**June 30, 2006**	**December 31, 2005**
Current retail derivative assets	$5.2	$55.0
Long-term retail derivative assets	0.1	12.9
Current retail derivative liabilities	(4.3)	(27.2)
Long-term retail derivative liabilities	-	0.4
Total retail	1.0	41.1
Retail hedges	-	24.1
Mark-to-market portfolio	$1.0	17.0

The methods used to determine the fair value of retail energy contracts are identified and segregated in the table of fair value of contracts at June 30, 2006 and December 31, 2005. A description of each method is as follows: 1) prices actively quoted primarily represent NYMEX futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards, including bilateral contracts for the purchase or sale of electricity or natural gas, and are marked to the mid-point of bid and ask market prices.

At June 30, 2006 and December 31, 2005, the sources of the fair value of retail energy contracts and for the three and six months ended June 30, 2006, the changes in fair value of these contracts are included in the following tables:

(Millions of Dollars)	**Fair Value of Retail Sourcing Contracts at June 30, 2006**		
Sources of Fair Value	**Maturity Less than One Year**	**Maturity of One to Four Years**	**Total Fair Value**

Prices actively quoted	$ -	$ -	$ -
Prices provided by external sources	0.9	0.1	1.0
Totals	$0.9	$0.1	$1.0

(Millions of Dollars)	Fair Value of Retail Sourcing Contracts at December 31, 2005		
Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Total Fair Value
Prices actively quoted	$ (8.8)	$ -	$(8.8)
Prices provided by external sources	25.8	-	25.8
Totals	$17.0	$ -	$17.0

(Millions of Dollars)	Three Months Ended June 30, 2006 Total Portfolio Fair Value	Six Months Ended June 30, 2006 Total Portfolio Fair Value
Fair value of retail contracts outstanding at beginning of period	$(12.7)	$17.0
Contracts realized or otherwise settled during the period	(1.0)	(5.8)
Changes in fair value recorded:		
Transferred to Hess	45.9	45.9
Other operating expenses	(23.9)	(47.6)
Fuel, purchased and net interchange power	(7.3)	(8.5)
Fair value of retail contracts outstanding at end of period	$ 1.0	$ 1.0

Changes in the fair value of retail contracts through the June 1, 2006 sale of the retail business totaling $23.9 million and $47.6 million for the three and six months ended June 30, 2006, respectively, are recorded in other operating expenses on the accompanying condensed consolidated statements of income/(loss). During the second quarter of 2006, $45.9 million of derivatives were transferred to Hess as a result of the sale of retail to Hess. In connection with the decision to exit the wholesale marketing business in March of 2005, Select Energy identified certain contracts previously designated as wholesale and redesignated them to support its retail marketing business. For the three and six months ended June 30, 2006, $7.3 million and $8.5 million of charges, respectively, were recorded in fuel, purchased and net interchange power on the condensed consolidated statements of income/(loss).

Competitive Generation Activities: The competitive generation assets owned by NU Enterprises are subject to certain operational risks, including but not limited to the length of scheduled and non-scheduled outages, bidding and scheduling with various ISOs, environmental issues and fuel costs. Competitive generation activities are also subject to various federal, state and local regulations. These risks may result in changes in the anticipated gross margins realized from competitive generation portfolio activities.

For the six months ended June 30, 2006, the Mt. Tom plant had an availability factor of 79.5 percent, while the 1,080 MW Northfield Mountain facility had an availability factor of 88.5 percent. The approximately 200 MW of hydroelectric units had an aggregate availability factor of 94.2 percent. During the second quarter of 2006, both the Mt. Tom plant and Northfield Mountain facility had significant outages. The Mt. Tom plant was shut down for approximately three weeks during the second quarter for an annual maintenance outage and to complete the installation of its new selective catalytic reduction system. One of the Northfield Mountain facility's four 270-MW units was off-line from April 3, 2006 through July 6, 2006 for repairs to the Unit 3 generator rotor assembly. NU Enterprises realized energy-related gross margin of approximately $6.9 million, which was not significantly impacted by these outages, in the six months ended June 30, 2006 primarily due to a favorable ratio of on-peak to off-peak energy prices for the Northfield Mountain facility early in the year and strong performance from the conventional hydro units throughout the first half of 2006.

The competitive generation business also receives revenues from sales of the ISO-NE products other than energy. The recent settlement agreement cleared by the FERC that proposed the adoption of transition period pricing and the FCM in place of the prior LICAP mechanism will increase capacity revenues above their current level.

Total competitive generation was 1.4 million MWhs through June 30, 2006. The Mt. Tom plant generated more than 0.4 million MWhs in the first half of 2006. NGC's Northfield Mountain facility generated approximately 0.5 million MWhs and other hydroelectric facilities generated approximately 0.5 million MWhs for the six months ended June 30, 2006. Conventional hydroelectric output benefited from above average rainfall.

The competitive generation business includes third party derivative generation related sales contracts (third party generation contracts) and physical generation from NGC and HWP (physical generation). At June 30, 2006 and December 31, 2005, Select Energy had generation derivative assets and derivative liabilities as follows:

(Millions of Dollars)	**June 30, 2006**	**December 31, 2005**
Current generation derivative assets	$ 7.1	$ 9.2

Long-term generation derivative assets	-	-
Current generation derivative liabilities	(11.9)	(5.1)
Long-term generation derivative liabilities	(8.1)	(15.5)
Portfolio	$(12.9)	$(11.4)

Certain generation derivatives are included in liabilities of assets held for sale. See Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements.

The methods used to determine the fair value of generation contracts are identified and segregated in the table of fair value of contracts at June 30, 2006 and December 31, 2005. A description of each method is as follows: 1) prices actively quoted primarily represent exchange traded futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards, including bilateral contracts for the purchase or sale of electricity and are marked to the mid-point of bid and ask market prices.

At June 30, 2006 and December 31, 2005, the sources of the fair value of generation contracts and for the three and six months ended June 30, 2006, the changes in fair value of these contracts are included in the following tables:

(Millions of Dollars)	**Fair Value of Generation Contracts at June 30, 2006**		
Sources of Fair Value	**Maturity Less than One Year**	**Maturity of One to Four Years**	**Total Fair Value**
Prices actively quoted	$ 2.5	$ -	$ 2.5
Prices provided by external sources	(7.3)	(8.1)	(15.4)
Totals	$(4.8)	$(8.1)	$(12.9)

(Millions of Dollars)	**Fair Value of Generation Contracts at December 31, 2005**		
Sources of Fair Value	**Maturity Less than One Year**	**Maturity of One to Four Years**	**Total Fair Value**
Prices actively quoted	$(1.8)	$ -	$ (1.8)
Prices provided by external sources	5.9	(15.5)	(9.6)
Totals	$ 4.1	$(15.5)	$(11.4)

(Millions of Dollars)	**Three Months Ended June 30, 2006**	**Six Months Ended June 30, 2006**
	Total Portfolio Fair Value	**Total Portfolio Fair Value**
Fair value of competitive generation contracts outstanding at beginning of period	$ (8.1)	$(11.4)
Contracts realized or otherwise settled during the period	(1.4)	(11.5)
Changes in fair value recorded:		
Discontinued operations	1.8	4.3
Wholesale contract market changes, net	(1.0)	(1.0)
Operating revenues	(4.2)	6.7
Fair value of competitive generation contracts outstanding at end of period	$(12.9)	$(12.9)

Changes in the fair value of generation contracts that became marked-to-market as a result of the decision to exit the remainder of the NU Enterprises' businesses totaled a positive $1.8 million and $4.3 million for the three and six months ended June 30, 2006, respectively, which is recorded in discontinued operations on the accompanying condensed consolidated statements of income/(loss). Changes in fair value of generation contracts that were marked to market as a result of the decision to exit the wholesale marketing business totaled a negative $1 million for the first half of 2006 and are recorded as wholesale contract market changes, net on the accompanying condensed consolidated statements of income/(loss). Changes in the fair value of energy contracts that remain in continuing operations totaling a negative $4.2 million for the three months ended June 30, 2006 and a positive $6.7 million for the six months ended June 30, 2006 are recorded as revenues on the condensed consolidated statements of income/(loss).

For further information regarding Select Energy's derivative contracts, see Note 5, "Derivative Instruments," to the condensed consolidated financial statements.

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 establishing credit limits prior to Select Energy's entering into contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes to economic, regulatory or other conditions. At June 30, 2006, approximately 29 percent of Select Energy's counterparty credit exposure to wholesale and trading counterparties was collateralized or rated BBB- or better. The composition of Select Energy s credit portfolio has shifted from being largely investment grade-rated to being non-rated. This is largely due to the divestiture of Select Energy s New England and retail portfolios. The bulk of the non-rated credit exposure is comprised of one counterparty (93 percent of total) that is a public instrumentality and political subdivision of the State of Connecticut. Select Energy was provided $6.7 million and $28.9 million of counterparty deposits at June 30, 2006 and December 31, 2005, respectively. For further information, see Note 1J, "Summary of Significant Accounting Policies - Counterparty Deposits," to the condensed consolidated financial statements.

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 those accounting policies and estimates it believes are most critical.

Discontinued Operations Presentation: In order for discontinued operations treatment to be appropriate, management must conclude that there is a component of a business that is "held for sale" in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and that it meets the criteria for discontinued operations. As of June 30, 2006, based on the status of exiting the NU Enterprises businesses, management concluded that discontinued operations presentation is appropriate for NGC, Mt. Tom, SESI, Woods Electrical, SECI-NH and Woods Network. The retail marketing business, which is held for sale, is not presented as discontinued operations because separate financial information is not available for this business for the periods prior to the first quarter of 2006. The wholesale marketing business is not held for sale. In November of 2005, NU Enterprises sold SECI-NH and Woods Network to unaffiliated buyers. In April of 2006, NU Enterprises sold certain assets of Woods Electrical. On May 5, 2006, NU Enterprises completed the sale of SESI. On June 1, 2006, NU Enterprises completed the sale of Select Energy's retail marketing business.

For further information regarding these companies, see Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements. Management will continue to evaluate this classification in 2006 for NU Enterprises' businesses that are being exited.

Impairment of Long-Lived Assets: The company evaluates long-lived assets such as property, plant and equipment to determine if these assets are impaired when events or changes in circumstances occur such as the 2005 announced decisions to exit the NU Enterprises businesses.

When the company believes one of these events has occurred, the determination needs to be made whether a long-lived asset should be classified as held and used or held for sale. For assets classified as held and used, the company estimates the undiscounted future cash flows associated with the long-lived asset or asset group and an impairment loss is recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. For assets held for sale, a long-lived asset or disposal group is measured at the lower of its carrying amount or fair value less cost to sell and depreciation of these assets is discontinued.

In order to estimate an asset's future cash flows, the company considers historical cash flows, changes in the market and other factors that may affect future cash flows. The company considers various relevant factors, including the method and timing of recovery, forward price curves for energy, fuel costs, and operating costs. Actual future market prices, costs and cash flows could vary significantly from those assumed in the estimates, and the impact of such variations could be material.

In the first quarter of 2006, management determined that the competitive generation business, which includes NGC and Mt. Tom, should be classified as assets held for sale rather than held and used. No impairment existed for the competitive generation assets as the fair value of these assets less their expected costs to sell exceeded their carrying values. Management determined that the best estimate for the fair value of the generation assets at June 30, 2006 were the bids received on July 10, 2006. The bids received were above carrying value, and therefore indicated that no impairment of the competitive generation assets existed at June 30, 2006.

For further information regarding impairment charges and assets held for sale, see Note 3, "Restructuring and Impairment Charges," and Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements.

Pension Plan Curtailment: NU s subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all regular NU employees. For the Pension Plan, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost is based on several significant assumptions. If these assumptions were changed, the resulting change in the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost could have a material impact on NU s condensed consolidated financial statements.

On December 15, 2005, the NU Board of Trustees approved a benefit for new non-union employees hired on and after January 1, 2006 to receive retirement benefits under a new 401(k) benefit rather than under the Pension Plan. Non-union employees actively employed on December 31, 2005 were given the choice in 2006 to elect to continue participation in the Pension Plan or instead receive a new employer contribution under the 401(k) Savings Plan effective on January 1, 2007. If the new benefit is elected, their accrued pension liability in the Pension Plan will be frozen as of December 31, 2006. Non-union employees are required to make this election by August 14, 2006. The approval of the new plan resulted in the recording of an estimated pre-capitalization, pre-tax curtailment expense of $6.2 million in 2005, as a certain number of employees were expected to elect the new 401(k) benefit, resulting in a reduction in aggregate estimated future years of service under the Pension Plan. Management estimated the amount of the curtailment expense associated with this change based upon actuarial calculations and certain assumptions, including the expected level of transfers to the new 401(k) benefit.

At this time, management believes that it is possible that the ultimate number of employees electing to leave the Pension Plan may be lower than previously estimated and that it is possible that a significant reduction in the estimated future years of service may not occur. The final impact of this benefit plan change will be determined in the third quarter of 2006.

Other Matters

Commitments and Contingencies: For further information regarding other commitments and contingencies, see Note 7, "Commitments and Contingencies," to the condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments: For updated information regarding NU's contractual obligations and commercial commitments at June 30, 2006, see Note 7C, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the condensed consolidated financial statements.

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. On March 5, 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). On March 12, 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

In an opinion dated October 12, 2005, 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. NU's request for a rehearing was denied on January 3, 2006. 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 opted not to seek review of this ruling by the United States Supreme Court. On April 7, 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. NU's motion asserts that NU is entitled to 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 stage, NU cannot predict the outcome of this matter or its ultimate effect on NU.

Proposed Accounting Pronouncements:

Employers Accounting for Defined Benefit Pension and Other Postretirement Plans: On March 31, 2006, the Financial Accounting Standards Board (FASB) issued an exposure draft, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106 and 132(R)." An exposure draft is not a final accounting pronouncement and is subject to change. If adopted as proposed, a company would be required to recognize the projected benefit pension and other postretirement plan obligations, net of the fair value of plan assets, on the balance sheet. The offsetting amount to the adjustment would be recognized in shareholders' equity in other comprehensive income. The exposure draft is expected to be effective on December 31, 2006, and is expected to be prospectively applied beginning on that date. To the extent the company is unable to receive rate treatment allowing for the establishment of regulatory assets or could not recognize such regulatory assets under GAAP, the final statement would have a material reduction of NU's shareholders' equity. See Note 11, "Pension Benefits and Postretirement Benefits Other Than Pensions," for information related to NU's defined benefit pension and other postretirement benefit plans.

Accounting Standard Issued But Not Yet Adopted:

A.

Accounting for Servicing of Financial Assets: In March of 2006, the FASB issued SFAS No. 156, "Accounting for Servicing of Financial Assets - An Amendment of FASB Statement No. 140." SFAS No. 156 requires an entity to recognize a servicing asset or liability at fair value each time it undertakes an obligation to service a financial asset by entering into a servicing contract in a transfer of the servicer's financial assets that meets the requirements for sale accounting and in other circumstances. Servicing assets and liabilities may be subsequently measured through either amortization or recognition of fair value changes in earnings. SFAS No. 156 is required to be applied prospectively to transactions beginning in the first quarter of 2007 and may affect the accounting treatment of CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. Implementation of this statement is not expected to have a material effect on the company's financial statements.

B.

Uncertain Tax Positions: On July 13, 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109." FIN 48 addresses the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. FIN 48 is required to be implemented in the first quarter of 2007 prospectively as a change in accounting principle with a cumulative effect adjustment reflected in the opening balance of retained earnings. The company is currently evaluating the potential impacts of FIN 48 on its financial statements.

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 by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, expiration or initiation of significant energy supply contracts, changes in levels of capital expenditures, developments in legal or public policy doctrines, technological developments, volatility in electric and natural gas commodity markets, effectiveness of risk management policies and procedures, changes in accounting standards and financial reporting regulations, fluctuations in the value of electricity positions, the methods, timing and results of disposition of competitive businesses, actions of rating agencies, terrorist attacks on domestic energy facilities and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports to the Securities and Exchange Commission (SEC). Management 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/(loss) for NU included in this report on Form 10-Q for the three and six months ended June 30, 2006:

	Income Statement Variances (Millions of Dollars) 2006 over/(under) 2005			
	Second Quarter	Percent	Six Months	Percent
Operating Revenues:	$ 139	9 %	$ 53	1 %
Operating Expenses:				
Fuel, purchased and net interchange power	126	13	(6)	-
Other operation	(6)	(2)	58	11
Wholesale contract market changes, net	(57)	(82)	(239)	(92)
Restructuring and impairment charges	1	55	(15)	(64)
Maintenance	(1)	(2)	1	1
Depreciation	5	8	8	7
Amortization	(25)	(a)	10	22
Amortization of rate reduction bonds	3	7	6	7
Taxes other than income taxes	1	2	4	3
Total operating expenses	47	3	(173)	(4)
Operating Income/(Loss)	92	(a)	226	(a)
Interest expense, net	-	-	5	4
Other income, net	2	23	12	73
Income/(Loss) before income tax expense	94	(a)	233	95
Income tax expense/(benefit)	41	(a)	87	90
Preferred dividends of subsidiary	-	-	-	-
Income/(loss) from continuing operations	53	(a)	146	96
Income from discontinued operations	(3)	(26)	12	(a)
Net Income/(Loss)	$ 50	(a) %	$ 158	(a) %

(a) Percent greater than 100.

Comparison of the Second Quarter of 2006 to the Second Quarter of 2005

Operating Revenues

Operating revenues increased $139 million in the second quarter of 2006 primarily due to higher distribution revenues ($189 million) and higher regulated transmission business revenues ($4 million), partially offset by lower revenues from NU Enterprises ($56 million).

Distribution revenues increased $189 million primarily due to higher electric distribution revenues. Higher 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 ($183 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 revenue tracking components increase of $183 million is primarily due to the pass through of higher energy supply costs ($158 million), higher CL&P FMCC charges ($17 million) and higher wholesale revenues ($9 million). The distribution component of these companies and the retail transmission component of PSNH which flow through to earnings increased $5 million primarily due to an increase in regulated retail rates, partially offset by a decrease in retail sales. Retail electric sales decreased 2.5 percent in 2006 compared with 2005. On a weather adjusted basis, retail electric sales were lower by 0.6 percent.

Transmission business revenues increased $4 million primarily due to a higher transmission investment base and the recovery of higher operating expenses in 2006 as allowed under FERC Tariff Schedule 21.

The NU Enterprises revenues decrease of $56 million is primarily due to the divesture of the competitive businesses which include the sale of the retail marketing business on June 1, 2006, the sale of the Massachusetts service location of SECI-CT in January 2006, and lower revenues from certain other competitive businesses not classified as discontinued operations.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses increased $126 million in the second quarter of 2006 primarily due to higher purchased power costs for distribution ($155 million), partially offset by lower costs at NU Enterprises ($30 million).

The $155 million increase in distribution purchased power costs is primarily due to higher standard offer supply costs for CL&P and WMECO ($121 million) and higher expenses for PSNH primarily due to higher energy costs ($35 million).

NU Enterprises lower costs of $30 million are primarily due to the divesture of the competitive businesses which include the sale of the retail marketing business on June 1, 2006.

Other Operation

Other operation expenses decreased $6 million in the second quarter of 2006 primarily due to lower NU Enterprises expenses of $33 million, partially offset by higher distribution and transmission expenses ($28 million).

NU Enterprises expenses decreased $33 million primarily due to the divesture of the competitive businesses which include exiting all of the New England wholesale marketing business in 2005 and the sale of the retail marketing business on June 1, 2006 ($15 million), the sale of the Massachusetts service location of SECI-CT in January 2006 ($13 million), and lower expenses from certain other competitive businesses not classified as discontinued operations ($5 million).

Higher distribution and transmission expenses of $28 million are primarily due to higher distribution reliability must run (RMR) costs and other power pool related expenses ($20 million), higher distribution uncollectible expenses ($3 million) and higher distribution and transmission employee related costs ($2 million).

Wholesale Contract Market Changes, Net

See Note 2, "Wholesale Contract Market Changes," to the condensed consolidated financial statements for a description and explanation of this amount.

Restructuring and Impairment Charges

See Note 3, "Restructuring and Impairment Charges," to the condensed consolidated financial statements for a description and explanation of this amount.

Maintenance

Maintenance expenses decreased $1 million in the second quarter of 2006 primarily due to lower transmission maintenance expenses.

Depreciation

Depreciation increased $5 million in the second quarter of 2006 primarily due to higher distribution and transmission plant balances.

Amortization

Amortization decreased $25 million in the second quarter of 2006 primarily due to PSNH distribution ($12 million) and CL&P distribution ($12 million). The PSNH decrease is primarily due to completing the recovery of its non-securitized stranded costs by offsetting the remaining stranded cost regulatory asset balances against an offsetting regulatory liability for the cumulative deferral of SCRC revenues. The CL&P decrease is primarily due to lower amortization related to distribution s recovery of transition charges ($10 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $3 million in the second quarter of 2006. 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 in the second quarter of 2006 primarily due to distribution s higher property taxes and higher Connecticut gross earnings tax related to higher CL&P distribution revenue.

Other Income, Net

Other income, net increased $2 million in the second quarter of 2006 primarily due to a $3 million gain associated with the sale of 2.7 million shares of Globix and higher CL&P Energy Independence Act (EIA) ($3 million), partially offset by the CYAPC regulatory asset write-off ($3 million).

Income Tax Expense/(Benefit)

Income taxes increased $41 million due to higher pre-tax earnings, the regulatory recovery of tax expense associated with nondeductible acquisition costs and an increase in state income taxes. The increase in state income taxes results from higher unitary taxable income due primarily to the sale of competitive generation assets.

Income from Discontinued Operations

For the three months ended June 30, 2006 and 2005, the operations of NGC, Mt. Tom, SESI and Woods Electric were presented as discontinued operation as a result of meeting certain criteria requiring this presentation. In addition, SECI-NH (including Reeds Ferry) and Woods Network are included in discontinued operations for the three months ended June 30, 2005. These businesses were sold in November of 2005. Under this presentation, revenues and expenses of these businesses are included in the income from discontinued operations on the condensed consolidated statement of loss. See Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed financial statements for a description and explanation of the discontinued operations.

<u>Comparison of the First Six Months of 2006 to the First Six Months of 2005</u>

Operating Revenues

Operating revenues increased $53 million in the first six months of 2006 primarily due higher distribution revenues ($403 million) and higher regulated transmission business revenues ($15 million), partially offset by lower revenues from NU Enterprises ($370) million.

Distribution revenues increased $403 million primarily due to higher electric distribution revenues ($414 million), partially offset by lower gas distribution revenues ($11 million). Higher 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 ($405 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 revenue tracking components increase of $405 million is primarily due to the pass through of higher energy supply costs ($339 million), higher CL&P FMCC charges ($51 million) and higher wholesale revenues ($15 million). The distribution component of these companies and the retail transmission component of PSNH which flow through to earnings increased $9 million primarily due to an increase in regulated retail rates, partially offset by a decrease in retail sales. Retail electric sales decreased 3.0 percent in 2006 compared with 2005, primarily due to a mild winter. On a weather adjusted basis, retail electric sales were lower by 0.8 percent.

Transmission business revenues increased $15 million primarily due to a higher transmission investment base and the recovery of higher operating expenses in 2006 as allowed under FERC Tariff Schedule 21.

The increase in electric distribution revenues is partially offset by lower gas distribution revenues of $11 million primarily due to lower sales volumes. Firm gas sales decreased 11.5 percent in 2006 compared with 2005 primarily due to a mild winter and increased conservation driven by higher gas costs. On a weather adjusted basis, firm gas sales decreased 3.9 percent.

The NU Enterprises revenues decrease of $370 million is primarily due to the divesture of the competitive businesses. Revenues in the wholesale marketing business decreased $365 million as a result of exiting all of its New England wholesale sales obligations in 2005 by either buying out those contracts or assigning its obligations to third parties. There were no additional contracts bought out or assigned in the first six months of 2006. NU Enterprises revenues also decreased primarily due to the sale of the Massachusetts service location of SECI-CT in January 2006 the winding down of the remaining SECI-CT contracts, and lower revenues from certain other competitive businesses not classified as discontinued operations ($32 million). These decreases are partially offset by an increase in the retail marketing business prior to its sale on June 1, 2006 ($27 million).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $6 million in the first six months of 2006 primarily due to lower costs at NU Enterprises ($360 million), partially offset by higher purchased power costs for distribution ($352 million).

NU Enterprises lower costs of $360 million are primarily due to the divesture of the competitive businesses. Wholesale marketing costs decreased $440 million primarily due to the absence of servicing the New England wholesale sales contracts that were exited in 2005. The remaining wholesale obligations in the PJM power pool expire in 2008 and the remaining wholesale obligation in New York continues through 2013. This decrease is partially offset by higher costs in the retail marketing business prior to its sale on June 1, 2006 ($80 million).

The $352 million increase in distribution purchased power costs is primarily due to higher standard offer supply costs for CL&P and WMECO ($307 million) and higher expenses for PSNH primarily due to higher energy costs ($51 million). The increase in distribution purchased power costs is partially offset by lower Yankee Gas expenses as a result of lower gas sales ($6 million).

Other Operation

Other operation expenses increased $58 million in the first six months of 2006 primarily due to higher distribution and transmission expenses ($53 million) and higher NU Enterprises expenses ($7 million).

Higher distribution and transmission expenses of $53 million are primarily due to higher distribution RMR costs and other power pool related expenses ($41 million), higher distribution and transmission employee related costs ($7 million) and higher distribution uncollectible expenses ($2 million).

NU Enterprises expenses increased $7 million primarily due to a charge to record the retail marketing business at its fair value less cost to sell ($54 million). Partially offsetting the increase is a $46 million decrease in NU Enterprises expenses primarily due to the divesture of the competitive businesses which include the sale of the Massachusetts service location of SECI-CT in January 2006 ($26 million), exiting all of the New England wholesale marketing business in 2005, and the sale of the retail marketing business on June 1, 2006 ($15 million), and lower expenses from certain other competitive businesses not classified as discontinued operations ($6 million).

Wholesale Contract Market Changes, Net

See Note 2, "Wholesale Contract Market Changes," to the condensed consolidated financial statements for a description and explanation of this amount.

Restructuring and Impairment Charges

See Note 3, "Restructuring and Impairment Charges," to the condensed consolidated financial statements for a description and explanation of this amount.

Maintenance

Maintenance expenses increased $1 million in the first six months of 2006 primarily due to higher transmission maintenance expenses.

Depreciation

Depreciation increased $8 million in the first six months of 2006 primarily due to higher distribution and transmission plant balances.

Amortization

Amortization increased $10 million in the first six months of 2006 primarily due to PSNH distribution ($22 million), partially offset by CL&P distribution ($10 million). The PSNH increase is primarily due to the overrecovery of ES costs in February and March of 2006 ($23 million) and the acceleration in the recovery of PSNH s non-securitized stranded costs ($11 million), partially offset by offsetting the remaining stranded cost regulatory asset balances against an offsetting regulatory liability for the cumulative deferral of SCRC revenues ($12 million). The CL&P decrease is primarily due to lower amortization related to distribution s recovery of transition charges ($9 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $6 million in the first six months of 2006. 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 in the first six months of 2006 primarily due to distribution s higher property taxes and higher Connecticut gross earnings tax related to higher CL&P distribution revenue.

Interest Expense, Net

Interest expense, net increased $5 million in the first six months of 2006, primarily due to the issuance of long-term debt of $350 million in 2005 and $250 million in 2006. The 2005 long-term debt issuance includes $200 million for CL&P in April and the issuance of $50 million per company related to Yankee Gas, WMECO and PSNH in July, August and October, respectively. The 2006 long-term debt issuance was $250 million for CL&P which was issued in June 2006. The increase is partially offset by interest related to the final decision on the streetlight refund docket recorded in the second quarter of 2005.

Other Income, Net

Other income, net increased $12 million in the first six months of 2006 primarily due to higher investment income ($7 million), which includes $2 million for CL&P related to a Connecticut tax refund claim settlement, a $3 million gain associated with the sale of 2.7 million shares of Globix and higher CL&P EIA incentives ($3 million). The increase is also due to higher AFUDC ($2 million), partially offset by the CYAPC regulatory asset write-off ($3 million).

Income Tax Expense/(Benefit)

Income tax benefit decreased $87 million due to lower pre-tax loss and the regulatory recovery of tax expense associated with non-deductible acquisition costs.

Income from Discontinued Operations

For the six months ended June 30, 2006 and 2005, the operations of NGC, Mt. Tom, SESI and Woods Electric were presented as discontinued operation as a result of meeting certain criteria requiring this presentation. In addition, SECI-NH (including Reeds Ferry) and Woods Network are included in discontinued operations for the six months ended June 30, 2005. These businesses were sold in November of 2005. Under this presentation, revenues and expenses of these businesses are included in the income from discontinued operations on the condensed consolidated statement of loss. See Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed 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 and the NU 2005 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, 2006:

	Income Statement Variances (Millions of Dollars) 2006 over/(under) 2005			
	Second Quarter	**Percent**	**Six Months**	**Percent**
Operating Revenues:	$ 143	18 %	$ 309	19 %
Operating Expenses:				
Fuel, purchased and net interchange power	116	24	244	24
Other operation	27	19	54	21
Maintenance	(1)	(3)	1	3
Depreciation	4	11	7	11
Amortization of regulatory (liabilities)/assets, net	(12)	(a)	(9)	(a)
Amortization of rate reduction bonds	2	8	4	7

Taxes other than income taxes		1	4		2	3
Total operating expenses		137	18		303	20
Operating Income		6	14		6	5
Interest expense, net		(2)	(6)		-	-
Other income, net		(1)	(10)		5	44
Income before income tax expense		7	45		11	20
Income tax expense		2	61		(1)	(8)
Net Income	$	5	40 %	$	12	32 %

(a) Percent greater than 100.

<u>Comparison of the Second Quarter of 2006 to the Second Quarter of 2005</u>

Operating Revenues

Operating revenues increased $143 million in the second quarter of 2006, compared with the same period in 2005, due to higher distribution revenues ($139 million) and higher transmission revenues ($4 million).

The distribution revenue increase of $139 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 ($136 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 rates which impact earnings increased $3 million, primarily due to higher retail rates as a result of the rate increase effective January 1, 2006 and the absence in 2006 of an additional reserve recorded in 2005 to reflect the final decision on the streetlight docket ($3 million), partially offset by decreased sales volumes. Retail sales in the second quarter of 2006 were 3.6 percent lower than the same period in 2005 and 1.4 percent lower on a weather normalized basis.

The distribution revenue tracking components increased $136 million primarily due to higher TSO related revenues ($118 million) and an increase in revenues associated with the recovery of FMCC charges ($17 million).

Transmission revenues increased $4 million primarily due to a higher rate base and higher operating expenses which are recovered under the NU schedule 21 tariff.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $116 million in the second quarter of 2006 primarily due to higher standard offer supply costs and higher purchased power costs as a result of higher energy prices.

Other Operation

Other operation expenses increased $27 million in the second quarter of 2006 primarily due to higher RMR costs ($18 million) which are tracked and recovered through the FMCC, higher pension, injuries and damages costs ($3 million), and higher C&LM expenses ($2 million) which are included in a regulatory rate tracking mechanism.

Maintenance

Maintenance expenses decreased $1 million in the second quarter of 2006 primarily due to lower expenses related to overhead lines maintenance ($1 million) and lower substation maintenance expenses ($1 million), partially offset by higher tree trimming expenses ($1 million).

Depreciation

Depreciation expense increased $4 million in the second quarter of 2006 due to higher utility plant balances resulting from plant additions.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $12 million in the second quarter of 2006 primarily due to lower amortization related to the recovery of transition charges ($10 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $2 million in the second quarter of 2006. 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 in the second quarter of 2006 primarily due to higher property taxes.

Interest Expense, Net

Interest expense, net decreased $2 million in the second quarter of 2006 primarily due to the absence of interest expense related to the final decision on the streetlight refund docket recorded in the second quarter of 2005 ($4 million) and lower rate reduction bond interest resulting from lower principal balances outstanding ($2 million), partially offset by higher short-term interest expense ($2 million) and higher interest on long-term debt mainly as a result of new debt issued in June 2006 ($1 million).

Other Income, Net

Other income, net decreased $1 million in the second quarter of 2006 primarily due to lower investment income ($1 million).

Income Tax Expense

Income tax expense increased $2 million in the second quarter of 2006 due to higher pre-tax earnings and a higher effective tax rate. The effective tax rate increased from 24.0 percent to 26.6 percent primarily due to higher plant and non-plant related flow through adjustments; partially offset by lower state tax expense resulting from higher credits.

Comparison of the First Six Months of 2006 to the First Six Months of 2005

Operating Revenues

Operating revenues increased $309 million in the first six months of 2006, compared with the same period in 2005, due to higher distribution revenues ($296 million) and higher transmission revenues ($12 million).

The distribution revenue increase of $296 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 ($291 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 rates which impact earnings increased $5 million, primarily due to higher retail rates as a result of the rate increase effective January 1, 2006 and the absence in 2006 of an additional reserve recorded in 2005 to reflect the final decision on the streetlight docket ($2 million), partially offset by decreased sales volumes. Retail sales for the first six months of 2006 were 3.9 percent lower than the same period in 2005 and 1.4 percent lower on a weather normalized basis.

The distribution revenue tracking components increased $291 million primarily due to higher TSO related revenues ($226 million), an increase in revenues associated with the recovery of FMCC charges ($51 million), and higher retail transmission revenues ($10 million).

Transmission revenues increased $12 million primarily due to a higher rate base and higher operating expenses which are recovered under the NU schedule 21 tariff.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $244 million in the first six months of 2006 primarily due to higher standard offer supply costs and higher purchased power costs as a result of higher energy prices, partially offset by deferred fuel costs.

Other Operation

Other operation expenses increased $54 million in the first six months of 2006 primarily due to higher RMR costs ($39 million) which are tracked and recovered through the FMCC, higher administrative and general costs which include pension and other benefit costs ($8 million), and higher C&LM expenses ($4 million) which are included in a regulatory rate tracking mechanism.

Maintenance

Maintenance expenses increased $1 million in the first six months of 2006 primarily due to higher tree trimming expenses ($2 million) and higher expenses related to underground lines maintenance ($1 million), partially offset by lower transformer and substation maintenance expenses ($2 million).

Depreciation

Depreciation expense increased $7 million in the first six months of 2006 due to higher utility plant balances resulting from plant additions.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $9 million in the first six months of 2006 primarily due to lower amortization related to the recovery of transition charges ($9 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $4 million in the first six months of 2006. 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 $2 million in the first six months of 2006 primarily due to higher property taxes.

Other Income, Net

Other income, net increased $5 million in the first six months of 2006 primarily due to interest income related to a Connecticut tax refund claim settlement ($2 million), higher EIA (Energy Independence Act) incentives ($3 million), higher other interest income ($2 million).

Income Tax Expense

Income tax expense decreased $1 million in the first six months of 2006 due to a lower effective tax rate; partially offset by higher pre-tax earnings. The effective tax rate decreased from 28.7 percent to 22 percent due to a favorable Connecticut refund claim settlement, higher state tax credits and a higher Medicare subsidy; partially offset by higher plant related flow through adjustments.

LIQUIDITY

Net cash flows from operations increased by $36.7 million from $46.1 million for the first half of 2005 to $82.8 million for the first half of 2006. The increase in operating cash flows is primarily due to changes in investments in securitizable assets which increased more in the first half of 2005 than in the first half of 2006. Investments in securitizable assets are affected by the level of accounts receivable and by the amount of accounts receivable sold through CRC to a financial institution. In the first half of 2006, the level of accounts receivable increased as compared to 2005, partially offset by the increase in the cash receipts from the sale of receivables to the financial institution totaling approximately $50 million in 2006 as compared to 2005. The increase in operating cash flows is offset by higher regulatory refunds as CL&P refunded previous overrecoveries to its ratepayers to moderate the increase in CL&P's TSO rates that became effective on January 1, 2006 and an estimated federal income tax payment of approximately $20 million related to CL&P's 2005 tax return. This payment was made in the first quarter of 2006. No such federal income tax payment was made in the first quarter of 2005. The company expects net cash flows to increase and CL&P refunds to decline in the second half of 2006 as a result of a DPUC decision to terminate a $0.009 per kWh credit on customer bills to refund previous CTA overrecoveries.

CL&P's capital expenditures totaled $240 million in the first half of 2006 compared to $181.7 million in the first half of 2005. This increase is primarily due to higher transmission capital expenditures. CL&P projects capital expenditures to total approximately $600 million in 2006.

Financing activities increased for the first half of 2006 primarily as a result of CL&P's $250 million debt issuance. On June 7, 2006, CL&P closed on the sale of $250 million, 30-year first mortgage bonds with a coupon rate of 6.35 percent. In addition, at June 30, 2006, CL&P's financing activities also included $60 million of capital contributions from NU, offset by dividend payments to NU of $31.9 million.

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 and the NU 2005 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, 2006:

	Income Statement Variances (Millions of Dollars) 2006 over/(under) 2005			
	Second Quarter	**Percent**	**Six Months**	**Percent**
Operating Revenues:	$ 44	17 %	$ 90	17 %
Operating Expenses:				
Fuel, purchased and net interchange power	35	28	50	20
Other operation	-	-	(1)	(1)
Maintenance	1	6	1	2
Depreciation	1	6	2	7
Amortization of regulatory assets, net	(12)	(74)	22	52
Amortization of rate reduction bonds	1	6	1	5
Taxes other than income taxes	-	-	1	3

Total operating expenses	26	11	76	16
Operating Income	18	77	14	29
Interest expense, net	(1)	(3)	-	-
Other income, net	-	-	1	(a)
Income before income tax expense	19	(a)	15	58
Income tax expense	13	(a)	13	(a)
Net Income	$ 6	64 %	$ 2	12 %

(a) Percent greater than 100.

<u>Comparison of the Second Quarter of 2006 to the Second Quarter of 2005</u>

Operating Revenues

Operating revenues increased $44 million in the second quarter of 2006, as compared to the same period in 2005, primarily due to higher distribution revenue ($43 million) and higher transmission revenue ($1 million). The distribution revenue increase of $43 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 ($42 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 and transmission components of PSNH s retail rates which impact earnings increased $1 million primarily due to the retail rate increases effective June 1, 2005, partially offset by lower retail sales. Retail sales decreased 0.4 percent in 2006 compared to the same period of 2005.

The distribution revenue tracking components increased $42 million primarily due to an increase in the ES rate component of retail revenues of $34 million, primarily due to an increase in the cost of fuel and purchased power.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power increased $35 million in the second quarter of 2006 primarily due to the higher cost of energy as a result of higher fuel prices.

Maintenance

Maintenance expenses increased $1 million in the second quarter of 2006 primarily due to higher boiler plant and overhead line maintenance expenses.

Depreciation

Depreciation expense increased $1 million in the second quarter of 2006 primarily due to higher plant balances.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net decreased $12 million in the second quarter as a result of PSNH completing the recovery of its non-securitized stranded costs by offsetting the remaining stranded cost regulatory asset balances against an offsetting regulatory liability for the cumulative deferral of SCRC revenues.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $1 million in the second quarter of 2006. The higher portion of principal within the rate reduction bonds payment results in a corresponding increase in the amortization of regulatory assets.

Interest Expense, Net

Interest expense, net decreased $1 million in the second quarter of 2006 primarily due to lower rate reduction bond interest resulting from lower principal balances outstanding ($1 million).

Income Tax Expense

Income tax expense increased $13 million due to higher pre-tax earnings and an increase in the effective tax rate (from 28.1 percent to 52.3 percent). The increase in the effective tax rate primarily results from higher state income tax expense and the regulatory recovery of tax expense associated with nondeductible acquisition costs. The increase in state income taxes results from higher unitary taxable income due primarily to the sale of competitive generation assets.

Comparison of the First Six Months of 2006 to the First Six Months of 2005

Operating Revenues

Operating revenues increased $90 million in the first six months of 2006, as compared to the same period in 2005, primarily due to higher distribution revenue ($87 million) and higher transmission revenue ($3 million). The distribution revenue increase of $87 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 ($83 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 and transmission components of PSNH s retail rates which impact earnings increased $4 million primarily due to the retail rate increases effective June 1, 2005 ($5 million), partially offset by lower retail sales ($1 million). Retail sales decreased 0.6 percent in 2006 compared to the same period of 2005.

The distribution revenue tracking components increased $83 million primarily due to an increase in the ES rate component of retail revenues of $80 million, primarily due to an increase in the cost of fuel and purchased power.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power increased $50 million in the first six months of 2006 primarily due to the higher cost of energy as a result of higher fuel prices.

Other Operation

Other operation expenses decreased $1 million in the first six months of 2006 primarily due to lower customer service expenses ($3 million) and lower load dispatch expenses ($2 million), partially offset by higher administrative expenses ($3 million) primarily due to higher pension and medical costs ($2 million).

Maintenance

Maintenance expenses increased $1 million in the first six months of 2006 primarily due to higher overhead line maintenance expenses ($2 million), partially offset by lower electric plant maintenance ($1 million).

Depreciation

Depreciation expense increased $2 million in the first six months of 2006 primarily due to higher plant balances.

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Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $22 million in the first six months as a result of the over-recovery of ES costs in February and March of 2006 ($23 million) and the acceleration of the recovery of PSNH's non-securitized stranded ($11 million) partially offset by offsetting the remaining stranded cost regulatory asset balances against an offsetting regulatory liability for the cumulative deferral of SCRC revenues.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $1 million in the first six months of 2006. 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 in the first six months of 2006 primarily due to higher property taxes.

Other Income/(Loss), Net

Other income/(loss), net increased $1 million in the first six months of 2006 primarily due to a higher allowance for funds used during construction (AFUDC) as a result of increased eligible CWIP for generation, lower short-term debt, and a greater component of CWIP being subject to a higher equity rate.

Income Tax Expense

Income tax expense increased $13 million due to higher pre-tax earnings and an increase in the effective tax rate (from 31.2 to 51.2 percent). The increase in the effective tax rate primarily results from higher state income tax expense and the regulatory recovery of tax expense associated with nondeductible acquisition costs. The increase in state income taxes results from higher unitary taxable income due primarily to the sale of competitive generation assets.

LIQUIDITY

Net cash flows from operations increased by $31.3 million from $85.2 million for the first half of 2005 to $116.5 million for the first half of 2006. The increase in operating cash flows is primarily due to an increase in accounts receivable collections. PSNH's operating cash flows are expected to decline in the second half of 2006 and thereafter as a result of a significant reduction in approved SCRC rates to an average rate of $0.0155 per kWh from the current average rate of $0.0335 per kWh effective on July 1, 2006. That decline, which amounts to approximately $170 million annually, is the result of the completion of PSNH's recovery of its Part 3 non-securitized stranded costs as of June 30, 2006.

PSNH's capital expenditures totaled $60.4 million in the first half of 2006 compared to $89.7 million in the first half of 2005. PSNH projects capital expenditures to total $150 million in 2006.

Financing activities for the first half of 2006 included the payment of $29.2 million in dividends to NU, compared to $12.3 million for the first half of 2005.

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 and the NU 2005 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, 2006:

Income Statement Variances

(Millions of Dollars)

2006 over/(under) 2005

	Second Quarter	Percent	Six Months	Percent
Operating Revenues:	$ 6	6 %	$ 30	15 %
Operating Expenses:				
Fuel, purchased and net interchange power	7	13	33	28
Other operation	(1)	(5)	(1)	(4)
Maintenance	(1)	(16)	(1)	(8)
Depreciation	-	-	-	-
Amortization of regulatory liabilities, net	(1)	(94)	(2)	(86)
Amortization of rate reduction bonds	-	-	-	-
Taxes other than income taxes	-	-	-	-

Total operating expenses		4	5		29	17
Operating Income		2	21		1	5
Interest expense, net		1	7		1	6
Other income, net		-	-		1	(a)
Income before income tax expense		1	32		1	9
Income tax expense		1	59		-	8
Net Income	$	-	- %	$	1	10 %

(a) Percent greater than 100.

Comparison of the Second Quarter of 2006 to the Second Quarter of 2005

Operating Revenues

Operating revenues increased $6 million in the second quarter of 2006, as compared to the same period in 2005, primarily due to higher distribution revenue ($7 million), partially offset by lower transmission revenue ($1 million). The distribution revenue increase of $7 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 ($6 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 revenue tracking components increase of $6 million is primarily due to the pass through of higher energy supply costs ($7 million), partially offset by lower retail transmission revenues ($1 million).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $7 million in the second quarter of 2006 primarily due to higher default service supply costs.

Other Operation

Other operation expenses decreased $1 million in the second quarter of 2006 primarily due to lower transmission costs and lower general and administrative expenses as a result of lower pension and other benefits costs.

Maintenance

Maintenance expenses decreased $1 million in the second quarter of 2006 primarily due to lower expenses related to overhead and underground lines maintenance and lower tree trimming expenses.

Amortization of Regulatory Liabilities, Net

Amortization of regulatory liabilities, net decreased $1 million in the second quarter of 2006 primarily due to a lower deferral of transition costs, as a result of higher default service expenses.

Interest Expense, Net

Interest expense, net increased $1 million in the second quarter of 2006 primarily due to higher long-term debt levels as a result of the issuance of $50 million of ten-year senior notes in August 2005.

Income Tax Expense

Income tax expense increased $1 million in the second quarter of 2006 due to higher pre-tax earnings and a higher effective tax rate. The effective tax rate increased from 43.8 percent to 52.8 percent primarily due to unfavorable variances in non-plant flow through differences and a 2006 state tax loss that provides no benefit.

<u>Comparison of the First Six Months of 2006 to the First Six Months of 2005</u>

Operating Revenues

Operating revenues increased $30 million in the first six months of 2006, as compared to the same period in 2005, primarily due to higher distribution revenue ($30 million). The distribution revenue increase of $30 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 ($30 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 revenue tracking components increase of $30 million is primarily due to the pass through of higher energy supply costs ($32 million), partially offset by lower retail transmission revenues ($2 million).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $33 million in the first six months of 2006 primarily due to higher default service supply costs.

Other Operation

Other operation expenses decreased $1 million in the first six months of 2006 primarily due to lower transmission costs.

Maintenance

Maintenance expenses decreased $1 million in the first six months of 2006 primarily due to lower tree trimming expenses.

Amortization of Regulatory Liabilities, Net

Amortization of regulatory liabilities, net decreased $2 million in the first six months of 2006 primarily due to a lower deferral of transition costs, as a result of higher default service expenses.

Interest Expense, Net

Interest expense, net increased $1 million in the first six months of 2006 primarily due to higher long-term debt levels as a result of the issuance of $50 million of ten-year senior notes in August 2005.

Other Income, Net

Other income, net increased $1 million in the first six months of 2006 primarily due to higher interest and dividend income, and higher C&LM incentive.

LIQUIDITY

Net cash flows from operations decreased by $18.3 million from $20 million for the first half of 2005 to $1.7 million for the first half of 2006. The decrease in operating cash flows is primarily due to an increase in the regulatory assets relating to a significant increase in the retail transmission costs driven by RMR costs that have been deferred and will be recovered from customers at a future date. Additionally, there was a decrease in the transition charge to customers of $13 million due to a significant 2004 overrecovery of the transition charge of approximately $56 million.

WMECO's capital expenditures totaled $20.8 million in the first half of 2006 compared to $20.9 million in the first half of 2005. WMECO projects total capital expenditures to total approximately $50 million in 2006.

At June 30, 2006, WMECO's financing activities included $20.5 million of capital contributions from NU, borrowings of $10 million from the Utility Group's revolving credit line, and the payment of $4 million in dividends to NU.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

The merchant energy business 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 expected to be reduced.

NU Enterprises - Wholesale Portfolio: When conducting sensitivity analyses of the change in the fair value of Select Energy s wholesale portfolio 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, 2006, Select Energy has calculated the market price resulting from a 10 percent change in forward market prices of those contracts. A 10 percent increase would have resulted in a pre-tax decrease in fair value of $6.3 million ($3.9 million after-tax) and a 10 percent decrease would have resulted in a pre-tax increase in fair value of $4.9 million ($3 million after-tax).

The impact of a change in electricity and natural gas prices on Select Energy's wholesale transactions at June 30, 2006 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.

NU Enterprises - Generation Portfolio: When conducting sensitivity analyses of the change in the fair value of merchant energy s generation portfolio 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. The merchant energy generation portfolio is comprised of primarily third party derivative generation related sales contracts (third party generation contracts) and physical generation from NGC and HWP (physical generation). In most instances, market prices and volatility are determined from quoted prices. Models are used for periods beyond 2009.

A hypothetical change in the fair value for generation contracts was determined assuming a 10 percent change in forward market prices. At June 30, 2006, a 10 percent increase in market price would have resulted in a pre-tax increase in fair value of $151 million ($93.3 million after-tax) and a 10 percent decrease would have resulted in a pre-tax decrease in fair value of $150.7 million ($93.1 million after-tax).

The impact of a change in electricity prices on merchant energy s generation portfolio at June 30, 2006, is 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 debt. At June 30, 2006, approximately 10.5 percent (19.3 percent including the debt subject to the fixed-to-floating interest rate swap of variable rate 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 variable-rate 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 debt subject to the fixed-to-floating interest rate swap, annual interest expense would have increased by $3.1 million. At June 30, 2006, NU parent maintained a fixed-to-floating interest rate swap to manage the interest rate risk associated with its $263 million of fixed-rate 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, requires 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 operating outside of the business lines that create or actively manage these risk exposures 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, 2006 and December 31, 2005, Select Energy maintained collateral balances from counterparties of $6.7 million and $28.9 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 $19 million and $103.8 million at June 30, 2006 and December 31, 2005 respectively.

The Utility Group has a lower level of credit risk related to providing regulated electric and gas distribution service than NU Enterprises. However, the Utility Group companies are subject to credit risk from certain long-term or high-volume supply contracts with energy marketing companies. The Utility Group manages the credit risk with these counterparties in accordance with established credit risk practices and maintains an oversight group that monitors contracting risks, including credit risk.

In 2005, NU adopted Enterprise Risk Management (ERM) as a methodology for managing the principle risks of the company. ERM involves the application of a well-defined, enterprise-wide methodology which 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.

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

ITEM 4.

CONTROLS AND PROCEDURES

NU evaluated the design and operation of its disclosure controls and procedures at June 30, 2006 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 concluded, based on their review, that NU s disclosure controls and procedures were 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 timeframes 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 significant changes in NU s internal controls over financial reporting during the quarter ended June 30, 2006 that have materially affected, or are reasonably likely to materially affect NU s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1.

LEGAL PROCEEDINGS

We are parties to various legal proceedings. We have identified these legal proceedings in Part I, Item 3, "Legal Proceedings" in our Annual Report on Form 10-K for the year ended December 31, 2005. There have been no material changes with regard to the legal proceedings previously disclosed in our most recent Form 10-K as such were updated by the disclosure of legal proceedings in our Quarterly Report on Form 10-Q for the period ended March 31, 2006.

ITEM 1A.

RISK FACTORS

NU is subject to a variety of significant risks in addition to the matters set forth under "Forward Looking Statements," in Item 2, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Other Matters." We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2005. NU s susceptibility to certain risks, including those discussed in detail in our Annual Report on Form 10-K, could exacerbate other risks. These risk factors should be considered carefully in evaluating NU s risk profile. With the exception of the risk factors described below, which descriptions have been modified to take into account certain recent events, there have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K as updated by the risk factors described in our Quarterly Report on Form 10-Q for the period ended March 31, 2006.

Risks Related to the Exit from the Competitive Businesses

On March 9, 2005, NU announced the decision to exit its wholesale marketing and energy services businesses, and on November 7, 2005, NU announced the decision to exit its retail marketing and competitive generation businesses, which constituted the remainder of NU s competitive businesses. NU has disposed of a substantial part of its wholesale business, closed on the sale of its retail marketing business on June 1, 2006, has sold four of its six services businesses and parts of a fifth, and contracted to sell its competitive generation assets to affiliates of ECP on July 24, 2006 for $1.34 billion.

The principle remaining risks from NU s competitive businesses are related to the unhedged portion of a large wholesale contract expiring in 2013. This wholesale contract carries the risk that Select Energy may have to serve higher-than-anticipated loads, which will vary depending on weather and other factors not in its control. Select Energy may settle this contract in the future, possibly at a cost higher than the present mark-to-market of the contract. In the first half of 2006, the wholesale marketing and competitive generation businesses were profitable, while the retail marketing business lost $72.3 million, due primarily to removing from retail certain of its wholesale supply contracts and the support from the competitive generation business. The sale of the retail business on June 1 ended NU s exposure to this business.

The financial reliability of Select Energy s counterparties and its ability to manage its wholesale marketing portfolio of contracts and assets within acceptable risk parameters will be of material importance to Select Energy until these contracts are divested. The net fair value position of the wholesale portfolio at June 30, 2006 was a net liability of $155.7 million for derivative contracts.

NU s decision to exit the competitive generation business could have material negative financial implications in 2006, if the expected sale of the competitive generation assets to ECP were delayed or cancelled. These could include the results of future asset impairment analyses, recognition of closure or exit costs in excess of estimates and recognition of other losses from disposing of or otherwise exiting this business. Such losses would not be realized if the sale to ECP is consummated as presently planned, by the end of 2006.

Exiting from Select Energy s remaining wholesale obligations could have an adverse impact on NU s liquidity, although any negative effect is expected to be mitigated by the sale of the competitive generation assets. To date, most of Select Energy s contract terminations have been on terms where Select Energy settled with its counterparty for a sum of money and obtained a full release from further liability on the contract. One significant wholesale contract settlement was, and future contract terminations may be, negotiated on terms whereby Select Energy s obligations are assigned or transferred to a credit-worthy third party, but a release from Select Energy s customer is not obtained. In such circumstances, Select Energy or another NU company will be liable to the customer should the third party default. Any such contingent liabilities could remain open for extended periods of time.

NU currently expects, but cannot assure, that it will substantially complete the exit from its competitive businesses by the end of 2006.

Risks Related to NU Enterprises Wholesale Marketing and Competitive Generation Businesses

A significant portion of Select Energy s competitive energy marketing activities has been providing electricity to full requirements customers, which are primarily regulated LDC and commercial and industrial retail customers. Under the terms of full requirements contracts, Select Energy is required to provide a percentage of the LDC s electricity requirements at all times. The volumes sold

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under these contracts vary based on the usage of the LDC s retail electric customers, and usage is dependent upon factors outside of Select Energy s control, such as unanticipated migration or inflow of customers. The varying sales volumes could be different than the supply volumes that Select Energy expected to utilize, either from its owned limited generation or from electricity purchase contracts, to serve the full requirements contracts. Differences between actual sales volumes and supply volumes can require Select Energy to purchase additional electricity or sell excess electricity, both of which are subject to market conditions such as weather, plant availability, transmission congestion, and potentially volatile price fluctuations that can impact prices and, in turn, Select Energy s margins.

Risks Related to Liquidity and Collateral Calls

NU s senior unsecured debt ratings by Moody s and S&P are currently Baa2 and BBB-, respectively, with stable outlooks. Were either of these ratings to decline to non-investment grade level, Select Energy could be asked to provide, as of June 30, 2006, approximately $154.3 million of collateral or LOCs to unaffiliated counterparties and approximately $81 million to several independent system operators and unaffiliated LDCs and LDCs under agreements largely guaranteed by NU. While NU s credit facilities are in amounts that would be adequate to meet calls at that level, NU s ability to meet any future calls would depend on its liquidity and access to bank lines of credit and the capital markets at such time.

Risks Associated With the Transmission Operations of NU s Utility Subsidiaries

NU, primarily through its subsidiary CL&P, has undertaken a substantial transmission capital investment program over the past several years and expects to invest approximately $2.3 billion in regulated electric transmission infrastructure from 2006 through 2010. Included in this amount is approximately $1.4 billion for costs associated with construction of two Connecticut 345 kV transmission lines from Middletown to Norwalk and Bethel to Norwalk; replacement of an undersea electric transmission line between Norwalk and Northport, New York; and two 115 kV underground transmission lines between Norwalk and Stamford, Connecticut. The regulatory approval process for these transmission projects has encompassed an extensive permitting, design and technical approval process. Various factors have resulted in increased cost estimates and delayed construction. 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 NU believes that all such expenses have been prudently incurred, NU cannot predict the outcome of future reviews should they occur.

The 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.

The successful implementation of NU s transmission construction plans is also subject to the risks that applicable permits or approvals are not issued or not timely issued, or issued with limiting or adverse conditions and/or that new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations all of which could impact NU s ability to meet its construction schedule, require NU to incur additional expenses and/or delay recovery of transmission costs from customers, and may adversely affect its ability to achieve forecasted levels of revenues.

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, 2006.

ITEM 4.

SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the Annual Meeting of Shareholders of NU held on May 9, 2006 the following ten nominees were elected to serve on the Board of Trustees by the votes set forth below:

	For	Withheld	Total
1. Richard H. Booth	129,734,242	2,408,229	132,142,471
2. Cotton M. Cleveland	126,920,426	5,222,045	132,142,471
3. Sanford Cloud, Jr.	129,695,662	2,446,809	132,142,471
4. James F. Cordes	129,765,305	2,377,166	132,142,471
5. E. Gail de Planque	126,591,015	5,551,456	132,142,471
6. John G. Graham	129,763,294	2,379,177	132,142,471
7. Elizabeth T. Kennan	126,696,502	5,445,969	132,142,471
8. Robert E. Patricelli	126,776,129	5,366,342	132,142,471
9. Charles W. Shivery	126,777,462	5,365,009	132,142,471
10. John F. Swope	126,785,207	5,357,264	132,142,471

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 2006. The vote ratifying such selection was 131,079,068 votes in favor and 676,347 votes against, and 387,056 abstentions.

CL&P. In a written Consent in Lieu of an Annual Meeting of Stockholders of CL&P dated June 30, 2006, stockholders voted to fix the number of directors for the ensuing year at three and the following three directors were elected, to serve on the Board of Directors for the ensuing year: Cheryl W. Grisé, Raymond P. Necci and Leon J. Olivier. The vote on each of these proposals was 6,035,205 shares in favor, representing 100 percent of the issued and outstanding shares of common stock of CL&P.

WMECO. In a written Consent in Lieu of an Annual Meeting of Stockholders of WMECO dated June 30, 2006 (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: Cheryl W. Grisé, David R. McHale, Leon J. Olivier and Rodney O. Powell. 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.

PSNH. In a written Consent in Lieu of an Annual Meeting of Stockholders of PSNH dated June 30, 2006 (PSNH 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: Cheryl W. Grisé, Gary A. Long, David R. McHale and Leon J. Olivier. The vote on each of these proposals was 301 shares in favor, representing 100 percent of the issued and outstanding shares of common stock of PSNH.

ITEM 6.

EXHIBITS

Document designated with a (*) are filed herewith.

(a)

Listing of Exhibits (NU)

<u>Exhibit No.</u>

<u>Description</u>

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Material Contracts

*10.11.7

Form of Amendment No. 10 to Power Contract, dated April 14, 2006 between YAEC and each of CL&P, PSNH and WMECO.

*10.33

Purchase and Sale Agreement dated July 24, 2006 between HWP and Mt. Tom Generating Company LLC.

*10.33.1

Guaranty dated July 24, 2006 of Energy Capital Partners I, LP for the benefit of HWP

*10.33.2

Guaranty dated July 24, 2006 of NU for the benefit of Mt. Tom Generating Company LLC

*10.34

Stock Purchase Agreement dated July 24, 2006 between NU Enterprises and NE Energy, Inc.

*10.34.1

Guaranty dated July 24, 2006 of Energy Capital Partners I, LP for the benefit of NU Enterprises

*10.34.2

Guaranty dated July 24, 2006 of NU for the benefit of NE Energy, Inc.

*10.35

Purchase and Sale Agreement dated July 24, 2006 by and among NGS, Select Energy, Northeast Utilities Service Company on the one hand, and NE Energy, Inc. on the other hand.

*10.35.1

Guaranty dated July 24, 2006 of Energy Capital Partners I, LP for the benefit of NGS, Select and Northeast Utilities Service Company

*10.35.2

Guaranty dated July 24, 2006 of NU for the benefit of NE Energy, Inc.

*10.36

Stock Purchase Agreement dated as of February 1, 2006 by and among Ameresco, Inc. ("Ameresco"), NU Enterprises and NU

*10.36.1

Extension Letter dated March 1, 2006 among NU Enterprises, NU and Ameresco.

*10.36.2

Extension Letter dated March 31, 2006 between NU Enterprises, NU and Ameresco.

*10.36.3

Stock Purchase Agreement Amendment and Waiver dated as of May 5, 2006 among NU Enterprises, NU and Ameresco.

*10.36.4

NU Indemnification Agreement dated as of May 5, 2006.

*10.36.5

Agreement to Purchase Contract Payments dated as of May 5, 2006 among NU, Ameresco and General Electric Capital Corporation.

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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 4, 2006

*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 4, 2006

*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 4, 2006

Listing of Exhibits (CL&P)

4.1.8

Supplemental Indenture (2006 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of June 1, 2006 ("Supplemental Indenture") (Exhibit 99.2 to CL&P Form 8-K filed June 7, 2006, File No. 0-00404)

*4.12.5

Amendment No. 6 to the Amended and Restated Receivables Purchase and Sales Agreement dated as of July 5, 2006.

*31

Certification of Cheryl W. Grisé, 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 4, 2006

*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 4, 2006

*32

Certification of Cheryl W. Grisé, 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 4, 2006

Listing of Exhibits (PSNH)

*31

Certification of Cheryl W. Grisé, 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 4, 2006

*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 4, 2006

*32

Certification of Cheryl W. Grisé, 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 4, 2006

Listing of Exhibits (WMECO)

*31

Certification of Cheryl W. Grisé, 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 4, 2006

*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 4, 2006

*32

Certification of Cheryl W. Grisé, 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 4, 2006

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 4, 2006 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 4, 2006 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 4, 2006	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 4, 2006	By	/s/ David R. McHale David R. McHale Senior Vice President and Chief Financial Officer (for the Registrant and as Principal Financial Officer)