NORTHEAST UTILITIES
Form 10-Q/A
March 17, 2005

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

FORM 10-Q/A
AMENDMENT NO. 2

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

For the quarterly period ended JUNE 30, 2004

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

Indicate by check mark whether the registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES X NO ___

Indicate by check mark whether the following registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act):

Northeast Utilities YES X NO ___

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, 2004
Northeast Utilities	
Common shares, $5.00 par value	128,232,433 shares

FORM 10-Q/A EXPLANATORY NOTE

Amendment No. 2 to this report eliminates the reference to our certifying officers' titles in certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. The certifications are included in Exhibits 31 and 31.1.

Amendment No. 1 to our quarterly report on Form 10-Q (Form 10-Q/A) was filed to amend the quarterly report on Form 10-Q for the quarter ended June 30, 2004 of Northeast Utilities (NU), which was originally filed on August 6, 2004 (Original Form 10-Q). Accordingly, pursuant to rule 12b-15 under the Securities Exchange Act of 1934, as amended, this Form 10-Q/A contains the complete text of Items 1, 2, and 4 of Part I and Item 6 of Part II, as amended, as well as certain currently dated certifications. Unaffected items from the quarterly reports of separate registrants The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (and associated certifications) have not been repeated in this Form 10-Q/A.

Subsequent to the filing of the Form 10-Q for the quarter ended June 30, 2004, NU concluded that it incorrectly applied accrual accounting for certain natural gas contracts established by the merchant energy segment to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. The natural gas basis contracts were originally accounted for on the accrual basis. The natural gas futures and swaps contracts were accounted for as cash flow hedges with changes in fair value reflected in other comprehensive income (a component of shareholders' equity). However, subsequent to the filing of the second quarter Form 10-Q, NU concluded that applying accrual accounting for the basis contracts was incorrect. The basis contracts should have been recorded at current fair value with changes in fair value impacting earnings. The fair value, which was a negative $0.9 million, has now been reflected in non-trading derivative liabilities and as an increase to fuel, purchased and net interchange power expenses. The futures and swaps contracts should not have been accounted for as cash flow hedges and should also have been recorded at fair value. The fair value, which was a positive $2.7 million and was previously reflected in other comprehensive income (a component of shareholders' equity), has now been reflected as a reduction of fuel, purchased and net interchange power expenses. This Form 10-Q/A reflects the change from accrual and hedge accounting to fair value accounting for the aforementioned natural gas derivative contracts. The net income impact of both of these restatements on both the second quarter and the six months ended June 30, 2004 is a positive $1.1 million.

The natural gas contracts discussed above are accounted for at fair value with changes in fair value included in earnings. NU concluded that fair value or mark-to-market accounting should have been applied. To correct this error, NU restated its condensed consolidated balance sheet as of June 30, 2004, the condensed consolidated statements of income for the three and six months ended June 30, 2004, and the condensed consolidated statement of cash flows for the six months ended June 30, 2004. NU has also restated the notes to its condensed consolidated financial statements as necessary to reflect the adjustments. Corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, and accounts payable, which had no impact on net income. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds were unrestricted and were used to or were available to fund the company's operations. The December 31, 2003 condensed consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate certain intercompany derivative assets and liabilities. For information regarding these restatements and the effects on significant financial statement line items, see Note 9, "Restatement of Previously Issued Financial Statements," to the condensed consolidated financial statements.

This amendment does not otherwise reflect events occurring after the filing of the Original Form 10-Q, which was filed on August 6, 2004. Such events include, among others, the events described in NU's quarterly report on Form 10-Q for the quarter ended September 30, 2004, and the events described in NU's current reports on Form 8-K filed after the filing of the Original Form 10-Q, except for those reports pertaining to this subject matter. Earnings guidance is not included in this Form 10-Q/A. For information regarding NU's most recent earnings guidance, see the current reports on Form 8-K dated January 26, 2005 and February 4, 2005.

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found in this report:

NU COMPANIES OR SEGMENTS

BMC..	BMC Energy LLC
CL&P.......................................	The Connecticut Light and Power Company
CRC..	CL&P Receivables Corporation
HWP..	Holyoke Water Power Company
NGC..	Northeast Generation Company
NGS..	Northeast Generation Services Company
NU or the company..........................	Northeast Utilities
NU Enterprises.............................	NU's competitive subsidiaries comprised of HWP, NG Energy, SESI, and Woods Network. For further infor 8, "Segment Information," to the condensed consoli statements.
PSNH.......................................	Public Service Company of New Hampshire
RMS..	R. M. Services, Inc.
Select Energy..............................	Select Energy, Inc. (including its wholly owned su
SENY.......................................	Select Energy New York, Inc.
SESI.......................................	Select Energy Services, Inc.
Utility Group..............................	NU's regulated utilities comprised of CL&P, PSNH, Yankee Gas. For further information, see Note 8, Information," to the condensed consolidated financ
WMECO......................................	Western Massachusetts Electric Company
Woods Network..............................	Woods Network Services, Inc.
Yankee.....................................	Yankee Energy System, Inc.
Yankee Gas.................................	Yankee Gas Services Company

THIRD PARTIES

Bechtel....................................	Bechtel Power Corporation
CYAPC......................................	Connecticut Yankee Atomic Power Company
NRG..	NRG Energy, Inc.

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

Act, the..................................	Public Act No. 03-135
CTA.......................................	Competitive Transition Assessment
EPS.......................................	Earnings per Share
FASB......................................	Financial Accounting Standards Board
FIN.......................................	FASB Interpretation
FMCC......................................	Federally Mandated Congestion Costs
FSP.......................................	FASB Staff Position
FTR.......................................	Financial Transmission Rights
GSC.......................................	Generation Service Charge
IERM......................................	Infrastructure Expansion Rate Mechanism
Incentive Plan............................	Northeast Utilities Incentive Plan
ISO-NE....................................	New England Independent System Operator
kWh.......................................	Kilowatt-hour
LMP.......................................	Locational Marginal Pricing
LOCs......................................	Letters of Credit
MW..	Megawatts
NU 2003 Form 10-K.........................	The Northeast Utilities and Subsidiaries combined as filed with the SEC
NYMEX.....................................	New York Mercantile Exchange
OCA.......................................	Office of Consumer Advocate
Restructuring Settlement..................	"Agreement to Settle PSNH Restructuring"
ROE.......................................	Return on Equity
RTO.......................................	Regional Transmission Organization
S&P.......................................	Standard & Poor's
SBC.......................................	System Benefits Charge
SCRC......................................	Stranded Cost Recovery Charge
SFAS......................................	Statement of Financial Accounting Standards
SMD.......................................	Standard Market Design
TSO.......................................	Transitional Standard Offer

Northeast Utilities and Subsidiaries

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

		June 30, 2004 (Restated)*
		(Thousands of D
ASSETS		
Current Assets:		
Cash and cash equivalents	$	48,680
Restricted cash - LMP costs		123,887
Special deposits		28,147
Investments in securitizable assets		190,388
Receivables, net		648,659
Unbilled revenues		102,597
Fuel, materials and supplies, at average cost		154,459
Derivative assets		365,988

Prepayments and other	69,106
	1,731,911
Property, Plant and Equipment:	
Electric utility	5,702,856
Gas utility	763,605
Competitive energy	902,871
Other	238,402
	7,607,734
Less: Accumulated depreciation	2,320,807
	5,286,927
Construction work in progress	354,823
	5,641,750
Deferred Debits and Other Assets:	
Regulatory assets	2,854,344
Goodwill	319,986
Purchased intangible assets, net	21,153
Prepaid pension	358,250
Other	454,831
	4,008,564
Total Assets	$ 11,382,225

* See Note 9.

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

June 30,
2004
(Restated)*

	(Thousands of Do
LIABILITIES AND CAPITALIZATION	
Current Liabilities:	
Notes payable to banks	$ 5,807
Long-term debt - current portion	89,114
Accounts payable	771,561
Accrued taxes	27,148
Accrued interest	43,310
Derivative liabilities	163,990
Counterparty deposits	104,976
Other	214,378
	1,420,284
Rate Reduction Bonds	1,639,344
Deferred Credits and Other Liabilities:	
Accumulated deferred income taxes	1,346,185
Accumulated deferred investment tax credits	101,000
Deferred contractual obligations	436,837
Regulatory liabilities	1,239,698
Other	248,818
	3,372,538
Capitalization:	
Long-Term Debt	2,510,927
Preferred Stock of Subsidiary - Non-Redeemable	116,200
Common Shareholders' Equity:	
Common shares, $5 par value - authorized 225,000,000 shares; 150,578,806 shares issued and 128,098,320 shares outstanding in 2004 and 150,398,403 shares issued and 127,695,999 shares outstanding in 2003	752,894
Capital surplus, paid in	1,110,135
Deferred contribution plan - employee stock ownership plan	(67,274)
Retained earnings	841,191
Accumulated other comprehensive income	45,010
Treasury stock, 19,573,433 shares in 2004 and 19,518,023 shares in 2003	(359,024)
Common Shareholders' Equity	2,322,932
Total Capitalization	4,950,059
Commitments and Contingencies (Note 4)	
Total Liabilities and Capitalization	$ 11,382,225

* See Note 9.

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,	
	2004 (Restated)*	2003
	(Thousands of Dollars, excep	
Operating Revenues	$ 1,524,666	$ 1,330,038
Operating Expenses:		
Operation -		
Fuel, purchased and net interchange power	912,418	767,002
Other	270,737	230,708
Maintenance	67,673	68,280
Depreciation	55,561	50,692
Amortization	28,087	22,890
Amortization of rate reduction bonds	38,294	35,303
Taxes other than income taxes	55,695	51,460
Total operating expenses	1,428,465	1,226,335
Operating Income	96,201	103,703
Interest Expense:		
Interest on long-term debt	33,998	28,546
Interest on rate reduction bonds	25,043	27,364
Other interest	4,097	3,617
Interest expense, net	63,138	59,527
Other Income, Net	2,862	754
Income Before Income Tax Expense	35,925	44,930
Income Tax Expense	10,544	16,672
Income Before Preferred Dividends of Subsidiary	25,381	28,258
Preferred Dividends of Subsidiary	1,389	1,389
Net Income	$ 23,992	$ 26,869
Basic and Fully Diluted Earnings Per Common Share	$ 0.19	$ 0.21

Basic Common Shares Outstanding (average)	128,033,513	126,747,117
Fully Diluted Common Shares Outstanding (average)	128,182,645	126,860,208

* See Note 9.

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,	
	2004 (Restated)*	
	(Thousands of Dollars	
Operating Activities:		
Income before preferred dividends of subsidiary	$ 94,213	$
Adjustments to reconcile to net cash flows provided by operating activities:		
Depreciation	110,134	
Deferred income taxes and investment tax credits, net	34,478	
Amortization	57,378	
Amortization of rate reduction bonds	81,293	
Amortization/(deferral) of recoverable energy costs	24,193	
Increase/(decrease) in prepaid pension	2,456	
Regulatory overrecoveries	8,753	
Other sources of cash	18,853	
Other uses of cash	(66,519)	
Changes in current assets and liabilities:		
Restricted cash - LMP costs	(30,257)	
Receivables and unbilled revenues, net	79,518	
Fuel, materials and supplies	51	
Investments in securitizable assets	(23,923)	
Other current assets	(26,430)	
Accounts payable	43,098	
Accrued taxes	(24,450)	
Other current liabilities	92,446	
Net cash flows provided by operating activities	475,285	
Investing Activities:		
Investments in plant:		
Electric, gas and other utility plant	(300,248)	
Competitive energy assets	(11,329)	

Cash flows used for investments in plant	(311,577)	
Buyout/buydown of IPP contracts	-	
Other investment activities	11,450	
Net cash flows used in investing activities	(300,127)	
Financing Activities:		
Issuance of common shares	2,786	
Repurchase of common shares	-	
Issuance of long-term debt	82,438	
Retirement of rate reduction bonds	(90,616)	
(Decrease)/increase in short-term debt	(99,193)	
Reacquisitions and retirements of long-term debt	(23,621)	
Cash dividends on preferred stock of subsidiaries	(2,779)	
Cash dividends on common shares	(38,379)	
Other financing activities	(486)	
Net cash flows (used in)/provided by financing activities	(169,850)	
Net increase in cash and cash equivalents	5,308	
Cash and cash equivalents - beginning of period	43,372	
Cash and cash equivalents - end of period	$ 48,680	$

* See Note 9.

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

NORTHEAST UTILITIES AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (All Companies)

A. Presentation

Restatement of Previously Issued Financial Statements: Subsequent to the filing of the Form 10-Q for the quarter ended June 30, 2004, Northeast Utilities (NU or the company) concluded that it incorrectly applied accrual accounting for certain natural gas contracts established to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. NU concluded that fair value accounting should have been applied. To correct this error, the financial and other information included herein has been restated for this change. Corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, accounts payable, derivative assets and derivative liabilities, which had no impact on net income. For further information regarding these restatements and the effects on significant financial statement line items, see Note 9, "Restatement of Previously Issued Financial Statements."

The accompanying unaudited condensed consolidated financial statements should be read in conjunction with this complete report on Form 10-Q/A, the First Quarter 2004 Form 10-Q, and the Annual Reports of NU, 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 NU 2003 Form 10-K, and the current reports on Form 8-K dated May 19, 2004 and July 14, 2004. The accompanying condensed consolidated financial statements contain, in the opinion of management, all adjustments necessary to present fairly NU's and the above companies' financial position at June 30, 2004, the results of operations for the three-month and six-month periods ended June 30, 2004 and 2003, and condensed consolidated statements of cash flows for the six-month periods ended June 30, 2004 and 2003. All adjustments are of a normal, recurring nature except those described in Note 1B. Due primarily to the seasonality of NU's business and to the quarterly earnings profile of NU Enterprises' merchant energy business segment in 2004, the results of operations and condensed consolidated statements of cash flows for the six-month periods ended June 30, 2004 and 2003, are not 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.

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

B. New Accounting Standards

Accounting for the Effect of Medicare Changes on Postretirement Benefits Other Than Pension (PBOP): On December 8, 2003, the President of the United States signed into law a bill that expands Medicare, primarily by adding a prescription drug benefit and by adding a federal subsidy to qualifying plan sponsors of retiree health care benefit plans. Management believes that NU currently qualifies for the subsidy for certain retiree groups.

Financial Accounting Standards Board (FASB) Staff Position (FSP) No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," required NU to make an election whether to either defer the impact of the subsidy until the FASB issues guidance or to reflect the impact of the subsidy on December 31, 2003 reported amounts. NU chose to reflect the impact on December 31, 2003 reported amounts with no impact on 2003 expenses, assets, or liabilities. The estimate of the actuarial gain, which decreased the PBOP benefit obligation, was refined in the first quarter of 2004 to $20 million and is currently being amortized as a reduction to PBOP expense over 13 years.

The estimated reduction in PBOP expense could change as a result of the completion of an actuarial estimate of the subsidy based on recent prescription drug claim experience. The subsidy estimate could also change as regulations are promulgated by the federal agencies responsible for administration of the Medicare program.

On May 19, 2004, the FASB issued FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," to provide guidance on accounting for the effects of the aforementioned Medicare expansion. This FSP supersedes FSP No. FAS 106-1 and concludes that the effects of the federal subsidy should be considered an actuarial gain and treated like similar gains and losses and requires certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits which are included in this report on Form 10-Q. The accounting treatment under FSP No. FAS 106-2 is consistent with FSP No. FAS 106-1 and with NU's accounting treatment at December 31, 2003.

C. Guarantees

NU provides credit assurance in the form of guarantees and letters of credit (LOCs) in the normal course of business, primarily for the financial performance obligations of NU Enterprises. NU would be required to perform under these guarantees in the event of non-performance by NU Enterprises, primarily Select Energy, Inc. (Select Energy). At June 30, 2004, the maximum level of exposure in accordance with FASB Interpretation No. (FIN) 45, "Guarantor's

Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," under guarantees by NU, primarily on behalf of NU Enterprises, totaled $897.7 million. Additionally, NU had $53 million of LOCs issued for the benefit of NU Enterprises outstanding at June 30, 2004.

CL&P had obtained surety bonds in the amount of $31.1 million related to the collection of March 2003 and April 2003 incremental locational marginal pricing (LMP) costs in compliance with a Connecticut Department of Public Utility Control (DPUC) order. Effective April 30, 2004, the DPUC approved CL&P's request to remove this surety bond requirement, and the surety bonds were cancelled. At June 30, 2004, NU had outstanding guarantees on behalf of the Utility Group of $11.2 million. This amount is included in the total outstanding NU guarantee exposure amount of $897.7 million.

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

On June 30, 2004, the Securities and Exchange Commission (SEC) issued an order allowing NU to expand its financial support of NU Enterprises. Under the order, NU has authorization from the SEC to provide up to $750 million of guarantees for NU Enterprises through June 30, 2007. The guarantees to the Utility Group are subject to a separate $50 million SEC limitation apart from the current $750 million guarantee limit. The amount of guarantees outstanding for compliance with the SEC limit for NU Enterprises at June 30, 2004 is $329.8 million, which is calculated using different, more probabilistic and fair-value based criteria than the maximum level of exposure required to be disclosed under FIN 45. FIN 45 includes all exposures even though they are not reasonably likely to result in exposure to NU.

D. Unbilled Revenues

Unbilled revenues represent an estimate of electricity or gas delivered to customers that has not been billed. Unbilled revenues represent assets on the condensed consolidated balance sheet that become accounts receivable in the following month as customers are billed. Such estimates are subject to adjustment when actual meter readings become available, when changes in estimating methodology occur and under other circumstances.

The Utility Group estimates unbilled revenues monthly using the requirements method. The requirements method utilizes the total monthly volume of electricity or gas delivered to the system and applies a delivery efficiency (DE) factor to reduce the total monthly volume by an estimate of delivery losses in order to calculate total estimated monthly sales to customers. The total estimated monthly sales amount less total monthly billed sales amount results in a monthly estimate of unbilled sales. Unbilled revenues are estimated by applying an average rate to the estimate of unbilled sales. The estimated DE factor can have a significant impact on estimated unbilled revenue amounts.

In accordance with management's policy of testing the estimate of

unbilled revenues twice each year using the cycle method of estimating unbilled revenues, testing was performed in the second quarter of 2004. The cycle method uses the billed sales from each meter reading cycle and an estimate of unbilled days in each month based on the meter reading schedule. The cycle method is more accurate than the requirements method when used in a mostly weather-neutral month.

The cycle method testing resulted in adjustments to the estimate of unbilled revenues that had a net positive after-tax earnings impact of $1.5 million in the second quarter of 2004. There were positive after-tax impacts on CL&P, WMECO and Yankee Gas of $1.8 million, $0.9 million, and $0.5 million, respectively, while there was a negative after-tax impact on PSNH of $1.7 million.

E. Regulatory Accounting

The accounting policies of NU's 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 Statement of Financial Accounting Standards (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' distribution business, continue to be cost-of-service rate regulated, and management believes that the application of SFAS No. 71 to those business portions of the aforementioned companies continues to be appropriate. Management also believes that it is probable that NU's operating companies will recover their 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.

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

	At June 30, 2004			
(Millions of Dollars)	NU Consolidated (1)	CL&P	PSNH	W
Recoverable nuclear costs	$ 62.7	$ 1.2	$ 31.5	$
Securitized assets	1,570.5	1,059.9	443.9	
Income taxes, net	264.0	151.4	42.2	
Unrecovered contractual obligations	359.1	211.6	66.3	
Recoverable energy costs	246.6	36.6	206.6	
Other	351.4	138.4	151.5	
Totals	$2,854.3	$1,599.1	$942.0	$2

	At December 31, 2003			
(Millions of Dollars)	NU Consolidated (1)	CL&P	PSNH	W
Recoverable nuclear costs	$ 82.4	$ 16.4	$ 33.3	$
Securitized assets	1,664.0	1,123.7	465.3	
Income taxes, net	253.8	140.9	44.2	
Unrecovered contractual obligations	378.6	221.8	69.9	
Recoverable energy costs	255.7	30.1	218.3	
Other	339.5	140.1	138.4	
Totals	$2,974.0	$1,673.0	$969.4	$2

(1) At June 30, 2004 and December 31, 2003, included in the table are $63.1 million and $63.4 million, respectively, of other regulatory assets, primarily associated with Yankee Gas' income

taxes, net and other regulatory assets related to environmental clean-up costs and hardship receivables.

Additionally, NU had approximately $12.6 million and approximately $12 million of regulatory costs at June 30, 2004 and December 31, 2003, 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 rates.

Regulatory Liabilities: The Utility Group maintained $1.2 billion of regulatory liabilities at both June 30, 2004 and December 31, 2003. These amounts are comprised of the following:

	At June 30, 2004			
(Millions of Dollars)	NU Consolidated (1)	CL&P	PSNH	W
Cost of removal	$ 333.2	$147.6	$ 88.8	
CTA, GSC and SBC overcollections	327.6	327.6	-	
Cumulative deferral - SCRC	175.8	-	175.8	
Regulatory liabilities offsetting Utility Group derivative assets	160.0	159.6	0.4	
LMP overcollections	83.8	83.8	-	
Other	159.3	78.6	22.9	
Totals	$1,239.7	$797.2	$287.9	

	At December 31, 2003			
(Millions of Dollars)	NU Consolidated (1)	CL&P	PSNH	W
Cost of removal	$ 334.0	$150.0	$ 88.0	$
CTA, GSC and SBC overcollections	333.7	333.7	-	
Cumulative deferral - SCRC	160.4	-	160.4	
Regulatory liabilities offsetting Utility Group derivative assets	116.9	115.4	1.5	
LMP overcollections	83.6	83.6	-	
Other	135.7	70.3	22.2	

Totals	$1,164.3	$753.0	$272.1	$

(1) At June 30, 2004 and December 31, 2003, included in the table are $123.1 million and $111.4 million, respectively, of other regulatory liabilities, associated with Yankee Gas' cost of removal, deferred gas costs, pension and other regulatory liabilities.

Estimated unbilled revenues for PSNH are not considered in the reconciliation of certain billed revenues to incurred costs through such rate mechanisms as the Stranded Cost Recovery Charge (SCRC) and the System Benefits Charge (SBC). Accordingly, changes in estimated unbilled revenues due to changes in these charges impact PSNH's earnings in the period of change.

F. 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:

	For the Six Months Ended	
(Millions of Dollars)	June 30, 2004	June 30, 200
Borrowed funds	$2.2	$2.7
Equity funds	1.9	3.3
Totals	$4.1	$6.0
Average AFUDC rates	3.7%	4.5%

G. Equity-Based Compensation

NU maintains an Employee Stock Purchase Plan and other long-term, equity-based incentive plans under the Northeast Utilities Incentive Plan. NU accounts for these plans under the recognition and measurement principles of Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No equity-based employee compensation cost for stock options is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table

illustrates the effect on net income and earnings per share (EPS) if NU had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," to equity-based employee compensation:

	For the Six Months
(Millions of Dollars, except per share amounts)	June 30, 2004 (Restated)
Net income, as reported	$91.4
Total equity-based employee compensation expense determined under fair value-based method for all awards, net of related tax effects	1.0
Pro forma net income	$90.4
EPS:	
Basic and fully diluted - as reported	$0.71
Basic and fully diluted - pro forma	$0.71

Net income as reported includes $1.6 million and $0.8 million expensed for restricted stock and restricted stock units for the six months ended June 30, 2004 and 2003, respectively. NU accounts for restricted stock in accordance with APB No. 25 and amortizes the intrinsic value of the award over the service period.

NU assumes an income tax rate of 40 percent to estimate the tax effect on total equity-based employee compensation expense determined under the fair value-based method for all awards.

During the six-month period ended June 30, 2004, no stock options were awarded.

On March 31, 2004, the FASB issued an exposure draft that, if finalized as proposed, would require NU to expense equity-based employee compensation under the fair value-based method beginning on January 1, 2005.

H. Sale of Customer Receivables

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 both June 30, 2004 and December 31, 2003, CL&P had sold accounts receivable of $80 million to the financial institution with limited recourse through CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. At June 30, 2004, the reserve requirements calculated in accordance with the Receivables Purchase and Sale Agreement were $19.5 million. This reserve amount is deducted from the amount of receivables eligible for sale at the time. 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 within its service territory. At June 30, 2004, amounts sold to CRC by CL&P but not sold to the financial institution totaling $190.4 million are included in investments in securitizable assets on

the accompanying condensed consolidated balance sheets. This amount would be excluded from CL&P's assets in the event of CL&P's bankruptcy. On July 7, 2004, CL&P renewed the arrangement with the financial institution through July 6, 2005.

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."

I. Other Investments

NU has an investment in the common stock of a developer of fuel cell and power quality equipment. Based on revised information that affected the fair value of NU's investment, management determined that at June 30, 2004, the value of NU's investment declined and that the decline was other than temporary in nature. An after-tax investment write-down of $2.4 million ($3.8 million on a pre-tax basis) was recorded to reduce the carrying value of the investment to $3.8 million.

Yankee Energy System, Inc. (Yankee) maintains a long-term note receivable from BMC Energy LLC (BMC), an operator of renewable energy projects. In late-March 2004, based on revised information that impacts undiscounted cash flow projections and fair value estimates, management determined that the fair value of the note receivable from BMC had declined and that the note was impaired. As a result, management recorded an after-tax investment write-down of $1.5 million ($2.5 million on a pre-tax basis) in the first quarter of 2004.

On June 30, 2004, Yankee sold virtually all of the assets and liabilities of R.M. Services, Inc. (RMS), a provider of consumer collection services, for $3 million. In conjunction with the sale, a gain totaling $0.6 million was included as a gain from the sale of RMS. For the three and six months ended June 30, 2004, RMS was consolidated into NU's condensed consolidated financial statements and had pre-tax losses totaling $0.7 million and $1.7 million, respectively. These amounts are recorded in other income - other, net on the accompanying condensed consolidated statements of income. For the three and six months ended June 30, 2003, which is before RMS was consolidated, Yankee recorded pre-tax investment write-downs totaling $1.1 million and $1.4 million, respectively, related to its investment in RMS.

These charges are disclosed in Note 1N, "Summary of Significant Accounting Policies - Other Income," and in the Eliminations and Other segment in Note 8, "Segment Information," to the condensed consolidated financial statements.

NU has an investment in the common stock of NEON Communications, Inc. (NEON), a provider of optical networking services. On July 19, 2004, NEON and Globix Corporation (Globix) announced a definitive merger agreement in which Globix, an unaffiliated publicly-owned entity would acquire NEON for shares of Globix common stock. If the merger is consummated, then NU would receive 1.2748 shares of Globix common stock for each of the 1.8 million shares of NEON stock it owns.

J. 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.

K. Counterparty Deposits

Balances collected from counterparties resulting from Select Energy's credit management activities totaled $105 million at June 30, 2004 and $46.5 million at December 31, 2003. 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 receive 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.

L. Special Deposits

Special deposits represents amounts Select Energy has on deposit with unaffiliated counterparties and brokerage firms in the amount of $2.6 million and amounts included in escrow for Select Energy Services, Inc. (SESI) that have not been spent on construction projects of $25.5 million at June 30, 2004. Similar amounts totaled $17 million and $32 million at December 31, 2003, respectively. Special deposits at December 31, 2003 also included $30.1 million in escrow that PSNH funded to acquire Connecticut Valley Electric Company, Inc. on January 1, 2004.

M. Restricted Cash - LMP Costs

Restricted cash - LMP costs represents incremental LMP cost amounts that have been collected by CL&P and deposited into an escrow account. At June 30, 2004 and December 31, 2003, restricted cash - LMP costs totaled $123.9 million and $93.6 million, respectively.

N. Other Income

The pre-tax components of NU's other income items are as follows:

	For the Three Months
(Millions of Dollars)	June 30, 2004

Investment write-downs	$(3.8)
Investment income	3.8
CL&P procurement fee	2.7
Charitable donations	(0.5)
AFUDC - equity funds	0.5
Gain on sale of RMS	0.6
Other, net	(0.4)
Totals	$2.9

	For the Six Months
(Millions of Dollars)	June 30, 2004
Investment write-downs	$(6.3)
Investment income	7.0
CL&P procurement fee	5.8
Charitable donations	(1.5)
AFUDC - equity funds	1.9
Gain on sale of RMS	0.6
Other, net	(3.0)
Totals	$ 4.5

O. Estimate of Workers' Compensation and Injuries and Damages Reserves

During the second quarter of 2004, NU engaged an actuary to assess the workers' compensation and injuries and damages reserves for claims incurred but not yet reported or included in specific case reserves. As a result of this assessment, these reserves were increased by $9.7 million resulting in an after tax charge of $2.8 million.

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

Derivatives that are utilized for trading purposes are recorded at fair value with changes in fair value included in earnings. Other contracts that are derivatives but do not meet the definition of a cash flow or fair value hedge and cannot be designated as normal purchases or normal sales are also 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, the changes in the fair value of the effective portion of those contracts are generally recognized in accumulated other comprehensive income until the underlying transactions occur. For contracts that meet the definition of a derivative but do not meet the hedging requirements, and for the ineffective portion of contracts that meet the cash flow hedge requirements, the changes in fair value of those contracts are recognized currently in earnings. Derivative contracts designated as fair value hedges and the item they are hedging are both recorded at fair value on the condensed consolidated balance sheets. Derivative contracts that are entered into as a normal purchase or sale and are probable of resulting in physical delivery, and are documented as such, are recorded under accrual accounting.

During the second quarter of 2004, a negative $27.2 million, net of tax, was reclassified as an expense from other comprehensive income in connection

with the consummation of the underlying hedged transactions and recognized in earnings. An additional $0.2 million, net of tax, was recognized in earnings for those derivatives that were determined to be ineffective and for the ineffective portion of cash flow hedges. A negative $0.1 million, net of tax, was recognized in earnings for the ineffective portion of fair value hedges. Also during the first quarter of 2004, new cash flow hedge transactions were entered into that hedge cash flows through 2006. As a result of these new transactions and market value changes since January 1, 2004, accumulated other comprehensive income increased by $19.3 million, net of tax. Accumulated other comprehensive income at June 30, 2004, was a positive $44.1 million, net of tax (increase to equity), relating to hedged transactions, and it is estimated that $42.2 million of this net of tax balance will be reclassified as an increase to earnings within the next twelve months. Cash flows from hedge contracts are reported in the same category as cash flows from the underlying hedged transaction.

The restatements discussed in Note 9, "Restatement of Previously Issued Financial Statements," resulted in $1.6 million being removed from accumulated other comprehensive income and being recognized as an increase in earnings. The restatements also resulted in a $0.5 million reduction in earnings for contracts previously recorded on an accrual basis now subject to fair value accounting.

The tables below summarize the derivative assets and liabilities at June 30, 2004 and December 31, 2003. The business activities of NU Enterprises that result in the recognition of derivative assets include concentrations of credit risk to energy marketing and trading counterparties. At June 30, 2004, the maximum amount of loss on trading, non-trading, and hedging contracts due to credit risk and assuming complete performance failure and no value for the collateral maintained is the total of NU Enterprises' derivative assets of $203 million. However, a significant portion of these assets is contracted with investment grade rated counterparties or collateralized with cash. The amounts below do not include option premiums paid, which are recorded as prepayments and amounted to $6.8 million and $9.1 million related to energy trading activities and $16.7 million and $7.6 million related to marketing activities at June 30, 2004 and December 31, 2003, respectively. These amounts also do not include option premiums received, which are recorded as other current liabilities and amounted to $9.2 million and $12.2 million related to energy trading activities at June 30, 2004 and December 31, 2003, respectively, and $1.9 million related to marketing activities at June 30, 2004.

		At June 30, 20
(Millions of Dollars)	Assets	Liabiliti
NU Enterprises:		
Trading	$111.2	$ (82
Non-trading	2.9	(1

Hedging	88.9	(15
Utility Group - Gas:		
Non-trading	-	(0
Hedging	3.0	-
Utility Group - Electric:		
Non-trading	160.0	(54
NU Parent:		
Hedging	-	(10
Total	$366.0	$(164

	At December 31,	
(Millions of Dollars)	Assets	Liabiliti
NU Enterprises:		
Trading	$ 71.8	$ (39
Non-trading	1.6	(0
Hedging	55.8	(12
Utility Group - Gas:		
Non-trading	0.2	(0
Hedging	2.8	-
Utility Group - Electric:		
Non-trading	116.9	(56
NU Parent:		
Hedging	-	(3
Total	$249.1	$(112

NU Enterprises - Trading: To gather market intelligence and utilize this information in risk management activities for the wholesale marketing activities, Select Energy conducts limited energy trading activities in electricity, natural gas, and oil, and therefore, experiences net open positions. Select Energy manages these open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures.

Derivatives used in trading activities are recorded at fair value and included in the condensed consolidated balance sheets as derivative assets or liabilities. Changes in fair value are recognized in operating revenues in the condensed consolidated statements of income in the period of change. The net fair value positions of the trading portfolio at June 30, 2004 and at December 31, 2003 were assets of $28.3 million and $32.5 million, respectively.

Select Energy's trading portfolio includes New York Mercantile Exchange (NYMEX) futures and options, the fair value of which is based on closing exchange prices; over-the-counter forwards and options, the fair value of which is based on the mid-point of bid and ask market prices; and bilateral contracts for the purchase or sale of electricity or natural gas, the fair value of which is determined using available information from external sources. Select Energy's trading portfolio also includes transmission congestion contracts (TCC). The fair value of the TCCs included in the trading portfolio is based on published market data.

NU Enterprises - Non-Trading: Certain Non-trading derivative contracts are used for delivery of energy related to Select Energy's wholesale and retail marketing activities. These contracts are subject to fair value accounting because these contracts are derivatives that cannot be designated as normal purchases or sales, as defined. These contracts cannot be designated as normal purchases or sales either because they are included in the New York energy market that settles financially or because management did not elect the normal purchases and sales designation.

Market information for the TCCs classified as non-trading is not available, and those contracts cannot be reliably valued. Management believes the amounts paid for these contracts, which total $8.2 million at June 30, 2004, and $4.3 million at December 31, 2003 are included in premiums paid, are equal to their fair value.

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Other non-trading natural gas derivative contracts with June 30, 2004 fair values of $1.8 million are used to mitigate the risk of electricity price changes on Select Energy's fixed-price electricity purchase contracts. These derivatives do not meet criteria to be accounted for as cash flow hedges and are accounted for at fair value as non-trading contracts. The contracts are natural gas basis and natural gas futures and swaps contracts with fair values determined by prices provided by external sources and actively quoted markets. Select Energy held none of these contracts at December 31, 2003.

NU Enterprises - Hedging: Select Energy utilizes derivative financial and commodity instruments, including futures and forward contracts, to reduce market risk associated with fluctuations in the price of electricity and natural gas purchased to meet firm sales commitments to certain customers. Select Energy also utilizes derivatives, including price swap agreements, call and put option contracts, and futures and forward contracts to manage the market risk associated with a portion of its anticipated supply and delivery requirements. These derivatives have been designated as cash flow hedging instruments and are used to reduce the market risk associated with fluctuations in the price of electricity, natural gas, or oil. A derivative that hedges exposure to the variable cash flows of a forecasted transaction (a cash flow hedge) is initially recorded at fair value with changes in fair value recorded 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.

Select Energy maintains natural gas service agreements with certain customers to supply gas at fixed prices for terms extending through 2006. Select Energy has hedged its gas supply risk under these agreements through NYMEX futures contracts. Under these contracts, which also extend through 2006, the purchase price of a specified quantity of gas is effectively fixed over the term of the gas service agreements. At June 30, 2004 the NYMEX futures contracts had notional values of $65.2 million and were recorded at fair value as derivative assets of $11.9 million.

Select Energy also maintains various physical and financial instruments to hedge its electric and gas purchases and sales through 2006. These instruments include forwards, futures, options, financial collars, swaps and financial transmission rights (FTRs). These hedging contracts, which are valued at the mid-point of bid and ask market prices, were recorded as derivative assets of $77 million and derivative liabilities of $14.7 million at June 30, 2004.

In the second quarter of 2004, Select Energy hedged natural gas inventory with gas futures, accounted for as fair value hedges. The changes in fair value of the futures, options and swaps were recorded as derivative liabilities of $0.5 million, and the changes in fair value of the hedged inventory of $0.9 million were recorded on the condensed consolidated balance sheets.

Utility Group - Gas - Non-Trading: Yankee Gas' non-trading derivatives consist of firm sales contracts with options to curtail delivery. These contracts are subject to fair value accounting because these contracts are derivatives that cannot be designated as normal purchases or sales, as defined, because of the optionality in the contract terms. The net fair

value of non-trading derivatives at June 30, 2004 was a liability of $0.1 million.

Utility Group - Gas - Hedging: Yankee Gas maintains a master swap agreement with a financial counterparty to purchase gas at fixed prices. Under this master swap agreement, the purchase price of a specified quantity of gas for an unaffiliated customer is effectively fixed over the term of the gas service agreements with that customer for a period not extending beyond 2005. At June 30, 2004 the commodity swap agreement had a notional value of $4.3 million and was recorded at fair value as a derivative asset of $3 million. The firm commitment contract that is hedged is also recorded as a liability on the accompanying condensed consolidated balance sheets, and changes in fair values of the hedge and firm commitment have offsetting impacts in earnings.

Utility Group - Electric - Non-Trading: CL&P has two independent power producer (IPP) contracts 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 to SFAS No. 133, as amended. The fair values of these IPP non-trading derivatives at June 30, 2004 include a derivative asset with a fair value of $152 million and a derivative liability with a fair value of $54.2 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 rates.

To mitigate the risk associated with certain supply contracts, CL&P purchased FTRs and financial swaps. FTRs and financial swaps are derivatives that do not qualify for the normal purchases and sales exception. The fair value of the FTR non-trading derivatives, valued at cost, at June 30, 2004 was an asset of $7.6 million. The fair value of the financial swap non-trading derivatives, which are valued at the mid-point of bid and ask market prices, at June 30, 2004 was a liability of $0.3 million.

To mitigate the risk associated with end user delivery, PSNH purchased FTRs. The fair value of PSNH's FTR non-trading derivatives, valued at cost, at June 30, 2004 was an asset of $0.4 million.

An offsetting regulatory asset or liability was recorded for CL&P and PSNH, as these contracts are part of procuring energy for requirements needs, and management believes that these costs will continue to be recovered or refunded in rates.

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. As a matched-terms fair value hedge, the changes in fair value of the swap and the hedged debt instrument are recorded on the condensed consolidated balance sheets but are equal and offsetting in the condensed consolidated statements of income. The cumulative change in the fair value of the hedged debt of $10.3 million is included as a reduction of long-term debt on the condensed consolidated balance sheets. The hedge is recorded as a derivative liability of $10.3 million. The resulting changes in interest payments made are recorded as adjustments to interest expense.

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

SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill and intangible assets deemed to have indefinite useful lives be reviewed for impairment at least annually by applying a fair value-based test. NU uses October 1st as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount. There were no impairments or adjustments to the goodwill balances during the six-month periods ended June 30, 2004 and 2003.

NU's reporting units that maintain goodwill are generally consistent with the operating segments underlying the reportable segments identified in Note 8, "Segment Information," to the condensed consolidated financial statements. Consistent with the way management reviews the operating results of its reporting units, NU's reporting units under the NU Enterprises reportable segment include: 1) the merchant energy reporting unit and 2) the energy services reporting unit. The merchant energy reporting unit is comprised of the operations of Select Energy, Northeast Generation Company (NGC) and the generation operations of Holyoke Water Power Company (HWP), while the energy services reporting unit is comprised of the operations of SESI, Northeast Generation Services Company (NGS) and Woods Network Services, Inc. (Woods Network). As a result, NU's reporting units that maintain goodwill are as follows: the Yankee Gas reporting unit, which is classified under the Utility Group - gas reportable segment; the merchant energy reporting unit, which is classified under the NU Enterprises - merchant energy reportable segment; and the energy services reporting unit, which is classified under NU Enterprises - eliminations and other. The goodwill balances of these reporting units are included in the table herein.

At June 30, 2004, NU maintained $319.9 million of goodwill that is no longer being amortized, $12.6 million of identifiable intangible assets subject to amortization and $8.5 million of intangible assets not subject to amortization. At December 31, 2003, NU maintained $319.9 million of goodwill that is no longer being amortized, $14.4 million of identifiable intangible assets subject to amortization and $8.5 million of intangible assets not subject to amortization. A summary of NU's goodwill balances at June 30, 2004 and December 31, 2003, by reportable segment and reporting unit is as follows:

(Millions of Dollars)	At June 30, 2004	At December 31,
Utility Group - Gas:		
Yankee Gas	$287.6	$287.6
NU Enterprises:		
Merchant Energy	3.2	3.2
Energy Services	29.1	29.1
Totals	$319.9	$319.9

The goodwill recorded related to the acquisition of Yankee Gas is not being recovered from the customers of Yankee Gas.

At June 30, 2004 and December 31, 2003, NU's intangible assets and related accumulated amortization, all of which related to NU Enterprises, consisted of the following:

		At June 30,
(Millions of Dollars)	Gross Balance	Accumula Amortizat
Intangible assets subject to amortization:		
Exclusivity agreement	$17.7	$8.5
Customer list	6.6	3.2
Totals	$24.3	$11.7
Intangible assets not subject to amortization:		
Customer relationships	$5.2	
Tradenames	3.3	
Totals	$8.5	

		At December 3
(Millions of Dollars)	Gross Balance	Accumula Amortizat

Intangible assets subject to amortization:		
Exclusivity agreement	$17.7	$ 7
Customer list	6.6	2
Totals	$24.3	$ 9

Intangible assets not subject to amortization:	
Customer relationships	$ 5.2
Tradenames	3.3
Totals	$ 8.5

NU recorded amortization expense of $1.8 million for both the six months ended June 30, 2004 and 2003, related to intangible assets. Based on the current amount of intangible assets subject to amortization, the estimated annual amortization expense for 2004 and for each of the succeeding 5 years from 2005 through 2009 is $3.6 million in 2004 through 2007 and no amortization expense in 2008 or 2009. These amounts may vary as acquisitions and dispositions occur in the future.

4. COMMITMENTS AND CONTINGENCIES

A. Restructuring and Rate Matters (CL&P, PSNH, WMECO)

Connecticut:

Impacts of Standard Market Design: On March 1, 2003, the New England Independent System Operator (ISO-NE) implemented Standard Market Design (SMD). As part of SMD, LMP is utilized to assign value and causation to transmission congestion and line losses. Transmission congestion costs represent the additional costs incurred due to the need to run uneconomic generating units in certain areas that have transmission constraints, which prevent these areas from obtaining alternative lower-cost generation. Line losses represent losses of electricity as it is sent over transmission lines.

CL&P was billed $186 million of incremental LMP costs in 2003 by its standard offer service suppliers, including affiliate Select Energy, or by ISO-NE and collected $158 million from its customers. CL&P and its suppliers disputed the responsibility for the $186 million of incremental LMP costs incurred. A settlement agreement was reached to

settle the dispute among all the parties involved and was filed with the Federal Energy Regulatory Commission (FERC) on March 3, 2004. NU recorded a pre-tax loss in 2003 of approximately $60 million (approximately $37 million after-tax) related to this settlement agreement. The settlement agreement was approved by the FERC on June 28, 2004.

On July 8, 2004, CL&P paid the standard offer service suppliers $83 million as part of the approved settlement agreement, and the remaining $75 million became available to be refunded to CL&P's customers. The method in which the $75 million will be refunded to customers is currently under review by the DPUC with a decision expected in the third quarter of 2004.

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 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 workers protection costs. The Generation Service Charge (GSC) allows CL&P to recover the costs of the procurement of energy for standard offer service.

On April 1, 2004, CL&P filed its 2003 CTA and SBC reconciliation with the DPUC. For the year ended December 31, 2003, total CTA revenues and excess GSC revenues as filed exceeded the CTA revenue requirement by $148.3 million. For the same period, SBC revenues as filed exceeded the SBC revenue requirement by $25.5 million. These amounts were recorded as regulatory liabilities on the accompanying condensed consolidated balance sheets.

A final decision in the 2003 CTA and SBC docket was issued on August 4, 2004. In the final decision, the DPUC ordered a refund to customers of $88.5 million over a seven-month period beginning with October 2004 consumption. The DPUC ordered that the SBC rate be reduced to zero effective January 1, 2005. The DPUC also directed CL&P to impute revenue of $2.7 million to customers associated with a previously renegotiated IPP contract. CL&P will likely seek rehearing on this issue, and management cannot predict the outcome of this issue at this time.

In the 2001 CTA and SBC reconciliation filing, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany liability associated with income taxes be excluded from 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. The appeal has been fully briefed and is in the argument phase, and a decision from the Connecticut Superior Court could be rendered by the end of 2004. If the company's request is ultimately granted through court proceedings, then there could be additional amounts due to CL&P from its customers. The 2004 impact of including the deferred intercompany liability in CTA revenue requirements has been a reduction of approximately $19.3 million in revenue.

New Hampshire:

SCRC Reconciliation Filing: The SCRC allows PSNH to recover its stranded costs. On an annual basis, PSNH files with the New Hampshire Public Utilities Commission (NHPUC) a SCRC reconciliation filing for the preceding calendar year. This filing includes the reconciliation of stranded cost revenues billed with stranded costs, and transition energy service (TS) revenues billed with TS costs. The NHPUC reviews the filing, including a prudence review of PSNH's generation operations. The cumulative deferral of SCRC revenues in excess of costs was $175.8 million at June 30, 2004. The 2003 SCRC filing was made on April 30, 2004. Management does not expect the review of the 2003 SCRC filing to have a material effect on PSNH's net income or financial position. Hearings are currently scheduled for October

2004.

Massachusetts:

Transition Cost Reconciliation: On March 31, 2004, WMECO filed its 2003 transition cost reconciliation with the Massachusetts Department of Telecommunications and Energy (DTE). This filing reconciled the recovery of generation-related stranded costs for calendar year 2003. The timing of a final decision is uncertain. Management does not expect the outcome of this docket to have a material adverse impact on WMECO's net income or financial position.

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

Certain subsidiaries of NU, including CL&P and Yankee Gas, have 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. On December 5, 2003, NRG emerged from bankruptcy. NU's NRG-related exposures as a result of these transactions relate to 1) the recovery of congestion charges incurred by NRG prior to the implementation of SMD on March 1, 2003, 2) the recovery of CL&P's station service billings from NRG, and 3) the recovery of Yankee Gas' and CL&P's expenditures that were incurred related to an NRG subsidiary's generating plant construction project that is now abandoned. 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 financial condition or results of operations.

C. Long-Term Contractual Arrangements (Select Energy)

Select Energy maintains long-term agreements to purchase energy in the normal course of business as part of its portfolio of resources to meet its actual or expected sales commitments. The aggregate amount of these purchase contracts was $4.7 billion at June 30, 2004, as follows (millions of dollars):

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Year	
2004	$2,441.3
2005	1,440.7
2006	299.1
2007	99.5
2008	83.7
Thereafter	295.7
Total	$4,660.0

Select Energy's purchase contract amounts can exceed the amount expected to be reported in fuel, purchased and net interchange power as energy trading purchases are classified net with the corresponding revenues.

NU's other long-term contractual arrangements have not changed significantly from the amounts reported at December 31, 2003.

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

The purchasers of NU's ownership shares of the Millstone, Seabrook and Vermont Yankee nuclear power plants assumed the obligation of decommissioning those plants, but NU still has significant decommissioning and plant closure cost obligations to the companies that own the Yankee Atomic (YA), Connecticut Yankee (CY) and Maine Yankee (MY) nuclear power plants (collectively, the Yankee Companies). Each plant has been shut down and is undergoing decommissioning. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements to several New England utilities, including NU's electric utility companies CL&P, PSNH and WMECO. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates. YA has received FERC approval to collect all presently estimated decommissioning costs. MY and various other parties filed a settlement agreement with the FERC. The MY settlement agreement includes the collection of approximately $27 million annually for decommissioning and long-term storage of spent fuel through October 31, 2008. Approval of the MY settlement agreement by the FERC is anticipated in the fall of 2004.

CY's estimated decommissioning and plant closure costs for the period 2000 through 2023 have increased by approximately $395 million over the April 2000 estimate of $436 million approved by the FERC in a 2000 rate case settlement. The revised estimate reflects the termination of the decommissioning contract with Bechtel Power Corporation (Bechtel) in July 2003, the fact that CY is now self-performing all work to complete the decommissioning of the plant, the increases in the projected costs of spent fuel storage, and increased security and liability and property insurance. NU's share of CY's increase in decommissioning and plant closure costs is approximately $194 million. On July 1, 2004, CY filed with the FERC for recovery of the increased costs. In the filing CY seeks to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning January 1, 2005. FERC proceedings have not yet been scheduled. In total, NU's estimated remaining decommissioning and plant closure obligation to CY is $315.5 million at June 30, 2004.

Previously, on June 10, 2004, the DPUC and the OCC filed a petition with the FERC seeking a declaratory order that CY can recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but such purchasers may not recover in their retail rates any costs which FERC might determine to have been imprudently incurred. CY and the wholesale purchasers have objected and the matter is pending.

NU cannot at this time predict the timing or outcome of the FERC proceeding required for the collection of the increased decommissioning costs. Management believes that these 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. For further information regarding these issues, see Part II, Item 1, "Legal Proceedings," in this report on Form 10-Q.

E. Consolidated Edison, Inc. Merger Litigation

Certain gain and loss contingencies continue to exist with regard to the 1999 merger agreement between NU and Consolidated Edison, Inc. (Con Edison) and the related litigation. Interrogatory appeals in the case are now pending, and no trial date has been set. At this stage of the litigation, management can predict neither the outcome of this matter nor its ultimate effect on NU.

5. COMPREHENSIVE INCOME (NU, CL&P, PSNH, WMECO, NU Enterprises)

Total comprehensive income, which includes all comprehensive income/(loss) items by category, for the six months ended June 30, 2004 and 2003 is as follows:

	Six Months Ended June 30, 2004 (R			
(Millions of Dollars)	NU	CL&P	PSNH	WMECO
Net income*	$ 91.4	$43.5	$17.8	$7.1
Comprehensive income/(loss) items:				
Qualified cash flow hedging instruments	19.3	-	-	-
Unrealized (losses)/gains on securities	(0.2)	-	-	-
Net change in comprehensive income/(loss) items	19.1	-	-	-
Total comprehensive income/(loss)	$110.5	$43.5	$17.8	$7.1

	Six Months Ended June 3			
(Millions of Dollars)	NU	CL&P	PSNH	WMECO
Net income*	$87.1	$30.0	$21.9	$8.7
Comprehensive (loss)/income items:				
Qualified cash flow hedging instruments	(13.9)	-	-	-
Unrealized gains on securities	0.7	0.1	-	-
Net change in comprehensive (loss)/income items	(13.2)	0.1	-	-
Total comprehensive income	$73.9	$30.1	$21.9	$8.7

* Net income after preferred dividends of subsidiary.

Amounts included in the Other column primarily relate to NU parent and Northeast Utilities Service Company.

Additionally, NU's total comprehensive income for the three months ended June 30, 2004 was $26.1 million.

Accumulated other comprehensive income fair value adjustments in NU's qualified cash flow hedging instruments for the six months ended June 30, 2004 and the twelve months ended December 31, 2003 are as follows:

(Millions of Dollars, Net of Tax)	At June 30, 2004	At D
Balance at beginning of period	$24.8	
Hedged transactions recognized into earnings	(27.2)	
Change in fair value	36.7	
Cash flow transactions entered into for the period	9.8	
Net change associated with the current period hedging transactions	19.3	
Total fair value adjustments included in accumulated other comprehensive income	$44.1	

Accumulated other comprehensive income items unrelated to NU's qualified cash flow hedging instruments totaled $0.9 million and $1.2 million in gains at June 30, 2004 and December 31, 2003, respectively. These amounts primarily relate to unrealized gains on investments in marketable debt and equity securities, net of related income taxes.

6. EARNINGS PER SHARE (NU)

EPS is computed based upon the weighted average number of common shares outstanding 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. At June 30, 2004 and 2003, 626,302 options and 2,862,471 options, respectively, were excluded from the following table as these options were antidilutive. The following table sets forth the components of basic and fully diluted EPS:

(Millions of Dollars, Except for Share Information)	Six Months Ended June 30, 2004 (Restated)	200
Income before preferred dividends of subsidiary	$94.2	$8
Preferred dividends		

of subsidiary	2.8	
Net income	$91.4	$8
Basic EPS common shares outstanding (average)	127,956,640	126,88
Dilutive effects of employee stock options	165,111	10
Fully diluted EPS common shares outstanding (average)	128,121,751	126,98
Basic and fully diluted EPS	$0.71	

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7. 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/(income) for the Pension Plan and the PBOP Plan for the six months ended June 30, 2004 and 2003 are estimated as follows:

	For the Six Months Ended June		
	Pension Benefits		Postre
(Millions of Dollars)	2004	2003	2004
Service cost	$ 20.3	$ 17.5	$ 3.0
Interest cost	59.4	58.5	12.7
Expected return on plan assets	(87.5)	(91.3)	(6.2)
Amortization of unrecognized net transition (asset)/obligation	(0.7)	(0.7)	5.9
Amortization of prior service cost	3.6	3.6	(0.2)
Amortization of actuarial loss/(gain)	7.8	(3.5)	-
Other amortization, net	-	-	5.7
Total - net periodic expense/(income)	$ 2.9	$(15.9)	$20.9

A portion of these expenses/(income) is capitalized related to employees working on capital projects.

NU does not expect to make any contributions to the Pension Plan in 2004. NU anticipates contributing approximately $10.4 million quarterly totaling $41.7 million in 2004 to fund its PBOP Plan.

The actuarial gain resulting from the expansion of the Medicare program decreased the PBOP accumulated plan benefit obligation by $20 million and is currently being amortized as a reduction to PBOP expense over 13 years. For the six months ended June 30, 2004, this reduction in PBOP expense totaled approximately $1.4 million, including amortization of the actuarial gain of $0.8 million and a reduction in interest cost based on a lower PBOP benefit obligation of $0.6 million.

As a result of ongoing litigation with nineteen former employees, in April 2004 NU was ordered by the court to modify its retirement plan to include special retirement benefits for fifteen of these former employees retroactive to the dates of their retirement. As NU appealed the ruling, these amounts are not included in the pension and PBOP information above.

There is no immediate impact of the court order, and if NU is ultimately required to provide retroactive benefits, then the amount of the benefits would be recorded as a pension plan amendment, which would be amortized as a prior service cost and would increase pension expense over a 13-year amortization period.

8. SEGMENT INFORMATION (All Companies)

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. Based on enhanced information that is reviewed by NU's chief operating decision maker, separate detailed information regarding the Utility Group's transmission businesses and NU Enterprises' merchant energy business is now included in the following segment information. Segment information for all periods has been restated to conform to the current presentation except for total asset information for the transmission business segment.

The Utility Group segment, including both the regulated electric distribution and transmission businesses, as well as the gas distribution business comprised of Yankee Gas, represents approximately 69 percent and 75 percent of NU's total revenues for the six months ended June 30, 2004 and 2003, respectively, and includes the operations of the regulated electric utilities, CL&P, PSNH and WMECO, whose complete condensed consolidated financial statements are included in NU's 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 Select Energy, NGC, the generation operations of HWP, and their respective subsidiaries, while the eliminations and other business segment includes SESI, NGS, Woods Network, and their respective subsidiaries and intercompany eliminations. The results of NU Enterprises parent are also included within eliminations and other.

Effective January 1, 2004, Select Energy began serving a portion of CL&P's transitional standard offer (TSO) load for 2004. Total Select Energy revenues from CL&P for CL&P's standard offer load, TSO load and for other transactions with CL&P, represented approximately $314.5 million or 22 percent for the six months ended June 30, 2004 and approximately $349.1 million or 30 percent for the six months ended June 30, 2003, of total NU Enterprises' revenues. Total CL&P purchases from NU Enterprises are eliminated in consolidation.

Additionally, WMECO's purchases from Select Energy for standard offer and default service and for other transactions with Select Energy represented approximately $53 million and $68.2 million of total NU Enterprises' revenues for the six months ended June 30, 2004 and 2003, respectively. Total WMECO purchases from NU Enterprises are eliminated in consolidation. Select Energy revenues related to contracts with NSTAR companies represented $158.4 million or 11 percent of total NU Enterprises' revenues for the six months ended June 30, 2004. Select Energy also provides BGS in the New Jersey market. Select Energy revenues related to these contracts represented $213.7 million or 18 percent of total NU Enterprises' revenues for the six months ended June 30, 2003. No other individual customer represented in excess of 10 percent of NU Enterprises' revenues for the six months ended June 30, 2004 or 2003.

Eliminations and other in the NU consolidated following tables includes the results for Mode 1 Communications, Inc., an investor in NEON, the results of the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, RMS, Yankee Energy Financial Services, and NorConn Properties, Inc.), the non-energy operations of HWP, the results of NU's parent and service companies, and write-downs of certain of the company's investments. Interest expense included in eliminations and other primarily relates to the debt of NU parent. Inter-segment eliminations of revenues and expenses are also included in eliminations and other. Eliminations and other includes NU's investment in RMS. Virtually all of the assets and liabilities of RMS were sold on June 30, 2004.

NU's segment information for the three months and six months ended June 30, 2004 and 2003 is as follows (some amounts between segment schedules may not agree due to rounding):

	For the Six Months Ended June 30, 20			
	Utility Group			
	Distribution			
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises
Operating revenues	$2,023.8	$ 243.3	$ 64.5	$1,417.4
Depreciation and amortization	(215.3)	(12.9)	(10.0)	(9.6)
Other				

operating expenses	(1,646.8)	(205.2)	(30.4)	(1,345.9)
Operating income/ (loss)	161.7	25.2	24.1	61.9
Interest Expense, net	(79.2)	(8.4)	(5.6)	(25.9)
Other income/ (loss), net	7.1	(0.6)	(0.2)	2.9
Income tax (expense)/ benefit	(30.9)	(4.1)	(5.8)	(16.1)
Preferred dividends	(2.8)	-	-	-
Net income/(loss)	$ 55.9	$ 12.1	$ 12.5	$ 22.8
Total assets (1)	$8,383.4	$1,058.0	$ -	$2,144.5
Total investments in plant	$ 189.3	$ 22.5	$ 81.3	$ 11.3

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(1) Information for segmenting total assets between electric distribution and transmission is not available at June 30, 2004. On a NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution column above.

For the Six Months Ended June 30, 20				
	Utility Group			
	Distribution			
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises
Operating revenues	$964.1	$72.0	$33.5	$ 621.1
Depreciation and amortization	(105.1)	(6.5)	(5.2)	(4.8)
Other operating expenses	(790.2)	(65.3)	(17.2)	(598.3)
Operating income/ (loss)	68.8	0.2	11.1	18.0
Interest expense, net	(39.3)	(4.5)	(3.3)	(12.2)
Other income/ (loss), net	3.8	(0.1)	0.2	1.6
Income tax (expense)/ benefit	(10.3)	4.6	(2.7)	(3.4)
Preferred dividends	(1.4)	-	-	-

Net income/(loss)	$ 21.6	$ 0.2	$ 5.3	$ 4.0

For the Six Months Ended June 30, 20				
	Utility Group			
	Distribution			
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises
Operating revenues	$1,894.0	$223.1	$55.8	$1,168.0
Depreciation and amortization	(226.0)	(11.5)	(9.2)	(10.2)
Other operating expenses	(1,500.6)	(181.7)	(27.8)	(1,107.0)
Operating income/ (loss)	167.4	29.9	18.8	50.8
Interest expense, net	(83.8)	(6.6)	(2.8)	(23.1)
Other(loss)/ income, net	(0.5)	(0.9)	(0.1)	2.8
Income tax (expense)/ benefit	(31.5)	(9.4)	(4.1)	(13.4)
Preferred dividends	(2.8)	-	-	-
Net income/(loss)	$ 48.8	$ 13.0	$11.8	$ 17.1
Total investments in plant	$ 155.5	$ 22.6	$43.8	$ 7.5

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For the Three Months Ended June 30, 2				
	Utility Group			
	Distribution			
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises
Operating revenues	$883.6	$ 72.1	$24.7	$555.1
Depreciation and amortization	(92.7)	(5.7)	(4.6)	(5.3)
Other operating expenses	(722.2)	(66.8)	(14.7)	(519.1)
Operating income/				

(loss)	68.7	(0.4)	5.4	30.7
Interest expense, net	(41.4)	(3.4)	(1.5)	(12.0)
Other(loss)/ income, net	(0.1)	(0.6)	-	2.5
Income tax (expense)/ benefit	(11.2)	1.5	(0.1)	(9.3)
Preferred dividends	(1.4)	-	-	-
Net income/(loss)	$ 14.6	$ (2.9)	$ 3.8	$ 11.9

Utility Group segment information related to the regulated electric distribution and transmission businesses for CL&P, PSNH and WMECO for the three months and six months ended June 30, 2004 and 2003 is as follows:

CL&P - For the Six Months Ended June 30, 2		
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$1,384.0	$43.8
Depreciation and amortization	(113.8)	(7.4)
Other operating expenses	(1,173.0)	(20.1)
Operating income	97.2	16.3
Interest expense, net	(50.7)	(4.2)
Other income, net	10.1	-
Income tax expense	(18.7)	(3.7)
Preferred dividends	(2.8)	-
Net income	$ 35.1	$ 8.4
Total investments in plant	$ 122.2	$66.2

CL&P - For the Three Months Ended June 30, 2004		
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$ 656.3	$22.8
Depreciation and amortization	(59.9)	(3.7)
Other operating		

expenses	(554.9)	(11.4)
Operating income	41.5	7.7
Interest expense, net	(25.2)	(2.6)
Other income, net	4.9	0.1
Income tax expense	(6.0)	(1.7)
Preferred dividends	(1.4)	-
Net income	$ 13.8	$ 3.5

CL&P - For the Six Months Ended June 30, 2		
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$1,285.6	$35.6
Depreciation and amortization	(149.1)	(6.9)
Other operating expenses	(1,042.8)	(18.6)
Operating income	93.7	10.1
Interest expense, net	(54.6)	(2.1)
Other income/ (loss), net	2.2	(0.2)
Income tax expense	(15.5)	(0.8)
Preferred dividends	(2.8)	-
Net income	$ 23.0	$ 7.0
Total investments in plant	$ 103.3	$33.9

CL&P - For the Three Months Ended June 30, 2		
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$599.5	$15.8
Depreciation and amortization	(70.4)	(3.4)
Other operating		

expenses	(495.3)	(9.5)
Operating income	33.8	2.9
Interest expense, net	(26.9)	(1.1)
Other income, net	1.2	-
Income tax (expense)/benefit	(4.8)	1.0
Preferred dividends	(1.4)	-
Net income	$ 1.9	$ 2.8

	PSNH - For the Six Months Ended June 30, 2	
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$457.6	$13.0
Depreciation and amortization	(81.5)	(1.7)
Other operating expenses	(328.7)	(7.0)
Operating income	47.4	4.3
Interest expense, net	(21.5)	(0.8)
Other loss, net	(2.2)	-
Income tax expense	(8.1)	(1.3)
Net income	$ 15.6	$ 2.2
Total investments in plant	$ 51.9	$13.7

	PSNH - For the Three Months Ended June 30, 2	
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$219.9	$ 6.5
Depreciation and amortization	(35.6)	(0.9)
Other operating expenses	(165.8)	(3.9)
Operating income	18.5	1.7
Interest		

expense, net	(10.6)	(0.4)
Other loss, net	(0.5)	-
Income tax expense	(2.2)	(0.5)
Net income	$ 5.2	$ 0.8

	PSNH - For the Six Months Ended June 30, 200	
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$421.4	$12.7
Depreciation and amortization	(42.8)	(1.4)
Other operating expenses	(322.6)	(6.2)
Operating income	56.0	5.1
Interest expense, net	(22.6)	(0.5)
Other (loss)/ income, net	(2.5)	0.1
Income tax expense	(11.9)	(1.8)
Net income	$ 19.0	$ 2.9
Total investments in plant	$ 40.7	$ 9.2

	PSNH - For the Three Months Ended June 30, 2	
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$197.9	$ 5.5
Depreciation and amortization	(6.1)	(0.7)
Other operating expenses	(163.3)	(3.6)
Operating income	28.5	1.2
Interest expense, net	(11.2)	(0.3)
Other loss, net	(1.2)	-
Income tax expense	(5.4)	(0.5)
Net income	$ 10.7	$0.4

WMECO - For the Six Months Ended June 30, 2		
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$182.3	$ 7.7
Depreciation and amortization	(20.1)	(0.9)
Other operating expenses	(145.1)	(3.3)
Operating income	17.1	3.5
Interest expense, net	(7.0)	(0.6)
Other loss, net	(0.9)	-
Income tax expense	(4.0)	(1.0)
Net income	$ 5.2	$ 1.9
Total investments in plant	$ 15.2	$ 1.4

WMECO - For the Three Months Ended June 30,		
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$ 88.0	$ 4.1
Depreciation and amortization	(9.6)	(0.5)
Other operating expenses	(69.6)	(1.8)
Operating income	8.8	1.8
Interest expense, net	(3.5)	(0.3)
Other loss, net	(0.6)	-
Income tax expense	(2.1)	(0.5)
Net income	$ 2.6	$ 1.0

WMECO - For the Six Months Ended June 30, 2		
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$186.9	$ 7.5
Depreciation and amortization	(34.1)	(0.9)
Other		

operating expenses	(135.1)	(3.0)
Operating income	17.7	3.6
Interest expense, net	(6.6)	(0.2)
Other loss, net	(0.2)	-
Income tax expense	(4.1)	(1.5)
Net income	$ 6.8	$ 1.9
Total investments in plant	$ 11.5	$ 0.7

	WMECO - For the Three Months Ended June 30,	
(Millions of Dollars)	Distribution	Transmission
Operating revenues	$ 86.4	$ 3.3
Depreciation and amortization	(16.2)	(0.5)
Other operating expenses	(63.7)	(1.5)
Operating income	6.5	1.3
Interest expense, net	(3.3)	(0.1)
Other loss, net	(0.2)	-
Income tax expense	(1.0)	(0.6)
Net income	$ 2.0	$ 0.6

NU Enterprises' segment information for the three months and six months ended June 30, 2004 and 2003 is as follows. Information regarding the energy services business segment is included in the eliminations and other column:

	NU Enterprises - For the Six Months	
(Millions of Dollars)	Merchant Energy	Eliminatio and Othe
Operating revenues	$1,285.0	$132.4

Depreciation and amortization	(8.6)	(1.0)
Other operating expenses	(1,212.7)	(133.2)
Operating income	63.7	(1.8)
Interest expense, net	(21.6)	(4.3)
Other (loss)/ income, net	(0.1)	3.0
Income tax (expense)/ benefit	(17.3)	1.2
Net income/(loss)	$ 24.7	$ (1.9)
Total assets	$1,833.0	$311.5
Total investments in plant	$ 9.9	$ 1.4

	NU Enterprises - For the Three Month	
(Millions of Dollars)	Merchant Energy	Eliminatio and Othe
Operating revenues	$ 550.5	$ 70.6
Depreciation and amortization	(4.3)	(0.5)
Other operating expenses	(525.8)	(72.5)
Operating income	20.4	(2.4)
Interest expense, net	(10.4)	(1.8)
Other income, net	-	1.6
Income tax (expense)/ benefit	(4.4)	1.0
Net income/(loss)	$ 5.6	$ (1.6)

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	NU Enterprises - For the Six Months	
(Millions of Dollars)	Merchant Energy	Elimination and Other
Operating revenues	$1,055.1	$112.9
Depreciation and		

amortization	(8.8)	(1.4)
Other operating expenses	(997.4)	(109.6)
Operating income	48.9	1.9
Interest expense, net	(19.9)	(3.2)
Other (loss)/ income, net	(2.2)	5.0
Income tax expense	(11.3)	(2.1)
Net income	$ 15.5	$ 1.6
Total investments in plant	$ 6.8	$ 0.7

	NU Enterprises - For the Three Months	
(Millions of Dollars)	Merchant Energy	Elimination and Other
Operating revenues	$ 492.1	$ 63.0
Depreciation and amortization	(4.4)	(0.9)
Other operating expenses	(458.6)	(60.5)
Operating income	29.1	1.6
Interest expense, net	(10.1)	(1.9)
Other (loss)/ income, net	(1.0)	3.5
Income tax expense	(7.4)	(1.9)
Net income	$ 10.6	$ 1.3

9. RESTATEMENT OF PREVIOUSLY ISSUED FINANCIAL STATEMENTS (NU, Select Energy)

Subsequent to the filing of the Form 10-Q for the quarter ended June 30, 2004, NU concluded that it incorrectly applied accrual accounting for certain natural gas contracts established by the merchant energy segment to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. NU concluded that fair value accounting for the aforementioned natural gas derivative contracts should have been applied. To correct this error, NU restated its condensed consolidated balance sheet as of June 30, 2004, the condensed consolidated statements of income for the three and six months ended June 30, 2004, and the condensed consolidated statement of cash flows and the condensed consolidated statement of comprehensive income for the six months ended June 30, 2004. NU has also restated the notes to its condensed consolidated financial statements as necessary to reflect the adjustments. Corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, and accounts payable, which had no impact on net income. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds are unrestricted and were used to or were available to fund the company's operations. The December 31, 2003 condensed consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate certain intercompany derivative assets and liabilities.

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The effects of the revisions on the condensed consolidated balance sheets as of June 30, 2004 and December 31, 2003, the condensed consolidated statements of income for the three and six months ended June 30, 2004, and the condensed consolidated statement of cash flows and condensed consolidated statement of comprehensive income for the six months ended June 30, 2004 are summarized in the following tables (in thousands, except share information):

Condensed Consolidated Balance Sheets	At J
	Previously Reported
Cash and cash equivalents	$ 75,265
Unrestricted cash from counterparties	104,976
Derivative assets	365,991
Accounts payable	903,122
Derivative liabilities	163,050
Accumulated deferred income taxes	1,346,602
Retained earnings	840,082
Accumulated other comprehensive income	46,645

	At Dec
	Previously Reported
Cash and cash equivalents	$ 37,196
Unrestricted cash from counterparties	46,496
Derivative assets	301,194
Accounts payable	768,783
Derivative liabilities	164,689

Condensed Consolidated Statements of Income	Three Months Ended June 30, 2004		Six J
	Previously Reported	As Restated	Previously Reported

Fuel, purchased and net interchange power	$914,200	$912,418	$2,091,511
Income before income tax expense	34,143	35,925	145,838
Income tax expense	9,871	10,544	52,734
Income before preferred dividends of subsidiaries	24,272	25,381	93,104
Net income	$ 22,883	$ 23,992	$ 90,325
Basic and fully diluted earnings per common share	$0.18	$0.19	$0.71

Condensed Consolidated Statement of Cash Flows	Six Months Ended June 30, 2004	
	Previously Reported	As Resta
Income before preferred dividends of subsidiary	$ 93,104	$ 94,21
Adjustments to reconcile net cash flows provided by operating activities:		
Other sources of cash	19,270	18,85
Other current assets	(26,433)	(26,43
Accounts payable	134,339	43,09
Other current liabilities	34,661	92,44
Other operating activities	253,105	253,10
Net cash flows provided by operating activities	508,046	475,28
Net increase in cash and cash equivalents	38,069	5,30
Cash and cash equivalents - beginning of period	37,196	43,37
Cash and cash equivalents - end of period	$ 75,265	$ 48,68

Additionally, NU's total comprehensive income for the three and six months ended June 30, 2004, which was $26.6 million and $111 million, respectively, has been restated and now totals $26.1 million and $110.5 million, respectively.

Condensed Consolidated Statement of Comprehensive Income	Six Months Ended June 30, 2004

	Previously Reported	As Resta
Net income	$ 90.3	$ 91.
Comprehensive income/(loss) items:		
Qualified cash flow hedging instruments	20.9	19.
Unrealized losses on securities	(0.2)	(0.
Net change in comprehensive income/(loss) items	20.7	19.
Total comprehensive income	$111.0	$ 110.

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NORTHEAST UTILITIES AND SUBSIDIARIES

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

FORM 10-Q/A EXPLANATORY NOTE

Subsequent to the filing of the Form 10-Q for the quarter ended June 30, 2004, NU concluded that it incorrectly applied accrual accounting for certain natural gas contracts established by the merchant energy segment to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. NU concluded that fair value, or mark-to-market, accounting should have been applied. To correct this error, NU restated its condensed consolidated balance sheet as of June 30, 2004, the condensed consolidated statements of income for the three and six months ended June 30, 2004, and the condensed consolidated statement of cash flows for the six months ended June 30, 2004. NU has also restated the notes to its condensed consolidated financial statements as necessary to reflect the adjustments. Corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, and accounts payable, which had no impact on net income. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds are unrestricted and were used to or were available to fund the company's operations. The December 31, 2003 condensed consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate certain intercompany derivative assets and liabilities. For information regarding these restatements and the effects on significant financial statement line items, see Note 9, "Restatement of Previously Issued Financial Statements," to the condensed consolidated financial statements. This Management's Discussion and Analysis of Financial Condition and Results of Operations gives effect to this restatement.

This amendment does not otherwise reflect events occurring after the filing of the Original Form 10-Q, which was filed on August 6, 2004. Such events include, among others, the events described in NU's quarterly report on Form 10-Q for the quarter ended September 30, 2004, and the events described in NU's current reports on Form 8-K filed after the filing of the Original Form 10-Q, except for those reports pertaining to this subject matter. For information regarding NU's most recent earnings guidance, see the current reports on Form 8-K dated January 26, 2005 and February 4, 2005.

This discussion should be read in conjunction with the condensed consolidated financial statements and footnotes in this Form 10-Q/A, the First Quarter 2004 Form 10-Q, the NU 2003 Form 10-K, and the current reports on Form 8-K dated May 19, 2004 and July 14, 2004. 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 report on Form 10-Q:

Results and Outlook:

- Earnings at Northeast Utilities (NU or the company) decreased by $2.9 million in the second quarter of 2004 compared with the same period of 2003, and increased by $4.3 million for the first six months of 2004 compared with the first six months of 2003.

- Results for the second quarter and first half of 2004 include the write-down of half of NU's $7.5 million investment in a developer of fuel cell and power quality equipment. That write-down reduced earnings by $0.02 per share.

- Regulated retail electric sales increased 4.6 percent in the first half of 2004, compared with the first half of 2003, on a weather adjusted basis. Second quarter retail electric sales increased 5.7 percent in 2004 compared with the same period of 2003, on a weather adjusted basis.

- NU is in the process of performing a comprehensive review of all of its business lines and developing five-year business plans. NU is also conducting an assessment of its corporate and shared services functions to ensure these functions are effectively aligned with NU's strategic plan.

Regulatory Items:

- On June 14, 2004, the transmission segment of NU's regulated companies reached a settlement agreement with parties to its rate case in the transmission rate case that allows transmission to implement formula-based rates as proposed with an 11.0 percent return on equity (ROE) until the Federal Energy Regulatory Commission (FERC) establishes an ROE for the regional transmission organization (RTO). The FERC is expected to issue a decision on the settlement agreement in the second half of 2004.

- A settlement agreement reached to settle the dispute over standard market design (SMD) locational marginal pricing (LMP) costs, which was filed with the FERC on March 3, 2004, was approved on June 28, 2004. The settlement agreement had no impact on 2004 earnings.

- The Connecticut Department of Public Utility Control (DPUC) issued a final decision on August 4, 2004, on reconsideration of items in the December 2003 Connecticut Light and Power Company (CL&P) distribution rate case decision. The final decision was generally favorable, and reconsideration was granted on all issues raised by CL&P.

- On July 2, 2004, Yankee Gas Services Company (Yankee Gas) filed a rate case with the DPUC to increase retail rates by $26.5 million, or 7.2 percent, effective January 1, 2005.

- On August 4, 2004, the DPUC issued a final decision accepting the settlement filed in April 2004 by Yankee Gas, which provided for the termination of Yankee Gas' Infrastructure Expansion Rate Mechanism (IERM).

- A settlement agreement was filed for approval in July 2004 with the New Hampshire Public Utilities Commission (NHPUC) to raise Public Service Company of New Hampshire (PSNH) retail distribution rates by $3.5 million on October 1, 2004 and $10 million on June 1, 2005.

- On July 19, 2004, the Massachusetts Department of Telecommunications and Energy (DTE) issued an order approving Western Massachusetts Electric Company's (WMECO) financing of its prior spent nuclear fuel liability through the issuance of up to $52 million in debt. WMECO plans to issue this debt by the end of 2004.

- In June 2004, the FERC approved a 40-year license extension for Northeast Generation Company's (NGC) Housatonic hydroelectric generation units in Connecticut. That license covers 115 megawatts (MW) of capacity.

Liquidity:

- At June 30, 2004, NU had $48.7 million of cash and cash equivalents compared with $43.4 million at December 31, 2003.

- On May 11, 2004, NU announced an 8.3 percent increase in its quarterly dividend. On September 30, 2004, NU will pay a dividend of $0.1625 per share to shareholders of record as of September 1, 2004.

- NU's capital expenditures have been lower than projected at the beginning of 2004. NU's capital expenditures totaled $311.6 million for the first six months of 2004, compared with $234 million for the first six months of 2003. NU's 2004 capital spending was originally budgeted to total $738 million, but is now projected to total $674.2 million due to delays in certain transmission projects.

Overview

Consolidated: NU earned $24 million, or $0.19 per share, in the second quarter of 2004, compared with earnings of $26.9 million, or $0.21 per share in the second quarter of 2003. For the first six months of 2004, NU earned $91.4 million or $0.71 per share, compared with earnings of $87.1 million, or $0.69 per share, in the first six months of 2003. The results for the second quarter of 2004 and first six months of 2004 include an after-tax write-down of $2.4 million, or $0.02 per share, of NU's investment in a developer of fuel cell and power quality equipment. NU's remaining investment in that company is $3.8 million. The results for the second quarter also include the positive after-tax impact of $1.1 million related to the mark-to-market accounting for certain natural gas contracts.

A summary of NU's earnings/(losses) by business segment for the second quarter and first six months of 2004 and 2003 is as follows:

	For the Three Months Ended June 30,		For the Si Ended Ju
(Millions of Dollars)	2004	2003	2004
Utility Group	$27.1	$15.5	$80.5
NU Enterprises	4.0	11.9	22.8
Other	(7.1)	(0.5)	(11.9)
Net income	$24.0	$26.9	$91.4

NU's revenues during the first six months of 2004 increased to $3.4 billion from $2.9 billion in the same period of 2003. The increase in revenues was primarily due to an increase of approximately $230 million in revenues at NU Enterprises'

merchant energy business segment as a result of $192 million in higher revenues from higher electric and gas prices and an increase in volumes that accounted for the remainder of that increase. NU's revenue increase is also the result of a $183 million increase in Utility Group revenues due to an increase in retail electric sales volume that accounted for $133 million of that increase and an increase in retail electric prices that accounted for the remainder of that increase.

Utility Group: The Utility Group is comprised of CL&P, PSNH, WMECO, and Yankee Gas. Earnings at the Utility Group increased by $11.6 million in the second quarter of 2004 compared with the same period of 2003, and increased by $6.9 million for the first six months of 2004 compared with the first six months of 2003. The increase in earnings for the first six months of the year was primarily due to an increase in retail electric sales of 3.7 percent. A summary of Utility Group earnings/(losses) by company for the second quarter and first six months of 2004 and 2003 is as follows:

	For the Three Months Ended June 30,		For the Six Ended Jun
(Millions of Dollars)	2004	2003	2004
CL&P *	$17.3	$ 4.7	$43.5
PSNH	6.0	11.1	17.8
WMECO	3.6	2.6	7.1
Yankee Gas	0.2	(2.9)	12.1
Net income	$27.1	$15.5	$80.5

*After preferred dividends

CL&P's higher earnings resulted from distribution and transmission rate increases that took effect January 1, 2004. These higher retail rates offset higher depreciation expense and higher pension expense. Additionally, CL&P also benefited from a 3.3 percent increase in retail electric sales.

PSNH's lower earnings were due primarily to higher pension expense and lower unbilled revenues.

The lower year-to-date earnings at WMECO were due to lower pension income and higher interest expense.

Yankee Gas' second quarter results benefited from a change in rate design implemented in August 2003 and lower income tax expense. Yankee Gas' current rate design is intended to recover more costs based on stable, fixed monthly charges rather than based on variable, usage-based charges as was the rate design in place earlier in 2003. That shift from more variable to more fixed charges will reduce quarterly earnings in the higher-use first and fourth quarters and improve quarterly results in the lower-use second and third quarters compared to Yankee Gas' previous rate design. Yankee Gas' results for the first six months of 2004 compared to 2003 continue to reflect the impact of the change in rate design. The reduction in income tax expense was a result of revisions to estimates of deferred taxes associated with Yankee Gas' plant assets.

Included in Utility Group earnings are earnings related to the regulated transmission business. Transmission business earnings were $5.3 million in the second quarter of 2004 and $12.5 million for the first six months of the year compared with earnings of $3.8 million in the second quarter of 2003 and $11.8 million for the first six months of 2003. Transmission business earnings for the

periods in 2004 are higher than the same periods in 2003 primarily due to higher revenues. Transmission revenues are higher in 2004 due to a revenue tracking mechanism that was put in place in 2004 to match revenues and costs of providing transmission service. In the first six months of 2004, $70.2 million of transmission projects were placed in service. The revenue tracking mechanism allows immediate recovery of these costs. During the first six months of 2003, revenues were not subject to such a tracking mechanism.

NU Enterprises: NU Enterprises, Inc. is the parent company of NGC, Northeast Generation Services Company (NGS), Select Energy, Inc. (Select Energy), Select Energy Services, Inc. (SESI), and their respective subsidiaries, and Woods Network Services, Inc. (Woods Network), all of which are collectively referred to as "NU Enterprises." The generation operations of Holyoke Water Power Company (HWP) are also included in the results of NU Enterprises. The companies included in the NU Enterprises segment are grouped into two business segments: the merchant energy business segment and the energy services business segment. The merchant energy business segment is comprised of Select Energy's wholesale business, which includes approximately 1,440 MW of primarily pumped storage and hydroelectric generation assets owned by NGC and Select Energy's retail business. The energy services business consists of the operations of NGS, SESI and Woods Network.

NU Enterprises earnings decreased by $7.9 million in the second quarter of 2004 compared with the second quarter of 2003, but increased by $5.7 million for the first six months of 2004 compared with the first six months of 2003. The improved six-month earnings are a result of improved margins and higher retail volumes on merchant energy contracts. A summary of NU Enterprises' earnings/(losses) by business for the second quarter and first six months of 2004 and 2003 is as follows:

	For the Three Months Ended June 30,		For the Si[x Months] Ended J[une 30,]
(Millions of Dollars)	2004	2003	2004
Merchant energy	$ 5.6	$10.6	$24.7
Energy services	(1.4)	1.4	(1.6)
Parent company	(0.2)	(0.1)	(0.3)
Net income	$ 4.0	$11.9	$22.8

A $5 million decrease in quarterly profitability was largely anticipated at the merchant energy business and was due primarily to the structuring of some of Select Energy's full requirements wholesale power contracts, which produced higher per megawatt-hour revenues in the first quarter of 2004 and lower revenues in the second quarter of 2004. Select Energy's cost per kilowatt-hour (kWh) for procuring electricity is relatively flat throughout 2004. However, contracted sales prices to some of Select Energy's wholesale customers were relatively high in the first quarter and were lower in the second quarter, creating better wholesale margins in the first quarter of 2004 and lower margins in the second quarter. This decrease was offset by the retail business' improved volumes and improved margins on those volumes. However, earnings were higher in the first half of 2004 compared with the first half of 2003 as a result of improved margins. Merchant energy second quarter earnings included an after-tax positive $1.1 million related to changes in fair value of certain natural gas contracts established to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. The use of fair value accounting for these contracts will likely result in earnings volatility in future periods.

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The decreases in second quarter and year-to-date earnings at the energy services business are due in part to a $1.8 million after-tax loss recorded in the second quarter on a construction contract.

Liquidity

Consolidated: NU continues to maintain an adequate level of liquidity. At June 30, 2004, NU had $48.7 million of cash and cash equivalents compared with $43.4 million at December 31, 2003.

NU's net cash flows provided by operating activities increased to $475.3 million in the first six months of 2004 from $211.7 million in the first six months of 2003. The increase is due to changes in working capital items, primarily accounts payable and accrued taxes. Accounts payable increased in the first six months of 2004 due primarily to an increase in CL&P accounts payable resulting from transitional standard offers (TSO) supply purchases at higher prices and an increased percentage of TSO purchases from unaffiliated suppliers. In the first six months of 2003, accounts payable decreased due to lower Select Energy wholesale electricity purchases. Accrued taxes decreased by $110 million in 2003 due primarily to the payment of taxes on the gain on the sale of Seabrook compared to a decrease of $24.5 million in 2004. These 2003 changes were partially offset by a decrease in accounts receivable related to a lower level of Select Energy sales in the first six months of 2003 compared to the last quarter of 2002 and a decrease in investments in securitizable assets and regulatory overrecoveries. The decrease in regulatory overrecoveries is primarily due to lower Competitive Transition Assessment (CTA) and Generation Service Charge (GSC) collections in the first six months of 2004, which is also the primary reason for the change in deferred income taxes from the first six months of 2003 to the first six months of 2004. The change in deferred income taxes is expected to continue to benefit cash flows from operations due to bonus tax depreciation on newly completed plant assets. Cash flows from operations, which have been significantly affected by changes in working capital items, are not necessarily indicative of the cash flows for the second half of 2004.

On June 30, 2004, NU paid a dividend of $0.15 per share. On May 11, 2004, the NU Board of Trustees approved a common dividend of $0.1625 per share, payable September 30, 2004, to shareholders of record at September 1, 2004. The dividend declared on May 11, 2004 represents an 8.3 percent increase in the common dividend. This increase is consistent with management's intention of recommending increases in the common dividend at a rate that is higher than the expected industry average.

NU's capital expenditures have been lower than projected at the beginning of 2004. NU's capital expenditures totaled $311.6 million for the first six months of 2004, compared with $234 million for the first six months of 2003. NU's 2004 capital spending was budgeted to total $738 million, but is now projected to total $674.2 million, including $383.7 million by CL&P, $152.4 million by PSNH, $39.4 million by WMECO, $60 million by Yankee Gas, and $38.7 million by other NU subsidiaries. The lower level of capital expenditures was primarily related to delays in certain transmission projects as a result of appeals of decisions by the Connecticut Siting Council (CSC) and other legal and regulatory delays. Further delays in certain major projects could cause NU's actual capital spending to be below this projection.

In June 2004, Standard & Poor's (S&P) announced a new method of calculating the capital adequacy of companies engaged in the competitive marketing and trading of electricity and natural gas. S&P stated that companies rated investment grade,

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such as NU and all of its regulated operating companies, should have the liquidity to meet whatever collateral requirements are necessitated by a simultaneous downgrade of NU's ratings to below investment grade and a significant movement in forward energy prices. NU continues to evaluate the future impact of the new S&P standard and may need to increase its credit lines to meet S&P's capital adequacy standards. At this time, management does not believe that the cost of any additional liquidity which may be required will have a material impact on future earnings.

Utility Group: At June 30, 2004, the Utility Group had $5 million in borrowings outstanding on its $300 million revolving credit line. This credit line is scheduled to mature in November 2004 and is expected to be renewed for at least one year.

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, 2004, CL&P had sold accounts receivable totaling $80 million to that financial institution. For more information regarding the sale of receivables, see Note 1H, "Summary of Significant Accounting Policies - Sale of Customer Receivables" to the condensed consolidated financial statements.

On June 23, 2004, the DPUC approved CL&P's request to issue up to $280 million of debt securities. CL&P expects to issue the debt later in 2004. Proceeds will be used to repay short-term debt and to refinance a $59 million, 8.5 percent bond issuance that will be redeemed on August 10, 2004 at a call premium of 3.87 percent. At June 30, 2004, CL&P had $196.2 million in short-term debt outstanding from the NU Money Pool.

As part of the approved SMD settlement agreement, CL&P paid $83 million to suppliers on July 8, 2004, and agreed to refund $75 million to its customers. Of the combined payment and refund amount totaling $158 million, $31 million has not been funded into the restricted cash - LMP costs account. Additionally, as part of the DPUC's final decision regarding CL&P's CTA and System Benefits Charge (SBC) docket, the DPUC ordered a refund to CL&P's customers of $88.5 million over a seven-month period beginning with October 2004 consumption. These refunds, when combined with CL&P's proposed capital projects and previously ordered refunds of CTA and SBC amounts, will negatively impact CL&P's liquidity. However, CL&P expects no difficulty funding these additional requirements.

On July 22, 2004, PSNH issued $50 million of first mortgage bonds at a fixed interest rate of 5.25 percent. Proceeds were used to pay down short-term debt and fund PSNH's capital expenditure program. At June 30, 2004, PSNH had $62.1 million in short-term debt outstanding from the NU Money Pool.

On July 19, 2004, the DTE issued an order approving WMECO's financing of its prior spent nuclear fuel liability through the issuance of up to $52 million in debt. WMECO plans to issue this debt by the end of 2004.

NU Enterprises: At June 30, 2004, NU Enterprises had $53 million in letters of credit (LOCs) outstanding on NU parent's $350 million revolving credit line. This credit line is scheduled to mature in November 2004 and is expected to be renewed for at least one year.

SESI borrowed $7.4 million during 2004 to finance the implementation of energy saving improvements at customer facilities. Cash to repay these borrowings is funded by SESI's energy savings contracts.

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Nuclear Decommissioning and Plant Closure Costs

The purchasers of NU's ownership shares of the Millstone, Seabrook and Vermont Yankee nuclear power plants assumed the obligation of decommissioning those plants, but NU still has significant decommissioning and plant closure cost obligations to the companies that own the Yankee Atomic (YA), Connecticut Yankee (CY) and Maine Yankee (MY) nuclear power plants (collectively, the Yankee Companies). Each plant has been shut down and is undergoing decommissioning. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements to several New England utilities, including NU's electric utility companies CL&P, PSNH and WMECO. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates. YA has received FERC approval to collect all presently estimated decommissioning costs. MY and various other parties filed a settlement agreement with the FERC, which if approved, provides for the collection of approximately $27 million annually for decommissioning and long-term storage of spent fuel through October 31, 2008. Approval of the MY settlement agreement by the FERC is anticipated in the fall of 2004.

CY's estimated decommissioning and plant closure costs for the period 2000 through 2023 have increased by approximately $395 million over the April 2000 estimate of $436 million approved by the FERC in a 2000 rate case settlement. The revised estimate reflects the termination of the decommissioning contract with Bechtel Power Corporation in July 2003, the fact that CY is now self-performing all work to complete the decommissioning of the plant, the increases in the projected costs of spent fuel storage, and increased security and liability and property insurance costs. NU's share of CY's increase in decommissioning and plant closure costs is approximately $194 million. On July 1, 2004, CY filed with the FERC for recovery of the increased costs. In the filing CY seeks to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning January 1, 2005. FERC proceedings have not yet been scheduled. In total, NU's estimated remaining decommissioning and plant closure obligation to CY is $315.5 million at June 30, 2004.

Previously, on June 10, 2004, the DPUC and the Office of Consumer Counsel filed a petition with the FERC seeking a declaratory order that CY can recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but such purchasers may not recover in their retail rates any costs which FERC might determine to have been imprudently incurred. CY and the wholesale purchasers have objected and the matter is pending.

NU cannot at this time predict the timing or outcome of the FERC proceeding required for the collection of the increased decommissioning costs. Management believes that these 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. For further information regarding these issues, see Part II, Item 1, "Legal Proceedings," in this report on Form 10-Q.

Utility Group Business Development and Capital Expenditures

Connecticut - CL&P: On July 14, 2003, the CSC approved a 345,000 volt transmission project from Bethel, Connecticut to Norwalk, Connecticut. The project is estimated to cost approximately $200 million and will help alleviate identified reliability issues in southwest Connecticut and help reduce congestion

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costs for all of Connecticut. An appeal of the CSC decision by the City of Norwalk is pending. Hearings on the merits of the appeal were held in early July 2004 and a decision on the appeal is expected this summer. Management is currently reassessing the project's expected cost and completion date. This project is exempt from the State of Connecticut's moratorium on the approval of new electric and natural gas transmission projects. At June 30, 2004, CL&P has capitalized $41.5 million associated with this project.

On October 9, 2003, CL&P and United Illuminating (UI) filed for approval of a separate 345,000 volt transmission line from Norwalk, Connecticut to Middletown, Connecticut. The estimated construction costs of this project are approximately $620 million. CL&P will jointly site this project with UI and CL&P will own 80 percent, or approximately $496 million, of the project. This project is also exempt from the State of Connecticut's moratorium on the approval of new electric and natural gas transmission projects. Hearings before the CSC began in February 2004 and are scheduled to continue through the third quarter of 2004, with a final CSC decision scheduled for December 2004. Construction is expected to commence shortly after the final decision. At June 30, 2004, CL&P has capitalized $13.2 million related to this project.

In September 2002, the CSC approved a plan to replace an undersea electric transmission line between Norwalk, Connecticut and Northport - Long Island, New York. The project is expected to cost approximately $100 million and CL&P and the Long Island Power Authority (LIPA) each own approximately 50 percent of the line. The project still requires federal and New York State approvals, but is exempt from the State of Connecticut's moratorium on the approval of new electric and natural gas transmission projects. On June 24, 2004, representatives from CL&P, the state of Connecticut, LIPA, and the Cross Sound Cable Company reached a comprehensive settlement of issues surrounding the activation of the separate Cross Sound Cable, in which NU has no investment. Among other items, the settlement agreement calls for the replacement of the existing Norwalk to Northport transmission line. A timetable for replacement of the line is due to be filed with the Connecticut Department of Environmental Protection by October 1, 2004. Management now expects the replacement cable to be operational by 2008. At June 30, 2004, CL&P has capitalized $6.5 million related to this project.

In the first six months of 2004, NU placed in service $70.2 million of electric transmission projects. These projects included CL&P's $36 million upgrade of a transmission substation in Stamford, Connecticut that will allow more than 100 additional MW to be imported into southwest Connecticut.

Connecticut - Yankee Gas: On June 10, 2004, Yankee Gas submitted a compliance filing with the DPUC concerning the construction of a 1.2 billion cubic foot liquefied natural gas storage facility in Waterbury, Connecticut. A final DPUC decision is anticipated in the third quarter of 2004. If that decision is acceptable to Yankee Gas, it is expected that Yankee Gas will enter into a final contract for the construction of the LNG facility, which is now expected to cost $108 million. Yankee Gas would anticipate beginning construction later in 2004 and for the facility to become operational in 2007 in time for the 2007/2008 heating season. This project is also exempt from the State of Connecticut's moratorium on the approval of new electric and natural gas transmission projects. At June 30, 2004, Yankee Gas has capitalized $4.1 million related to this project.

New Hampshire: In May 2004, PSNH received final approval from the NHPUC to convert one of three 50 megawatt units at the coal-fired Schiller Station to burn wood. In its final decision, the NHPUC approved a joint motion for

reconsideration with the Office of Consumer Advocate (OCA), the state Office of Energy and Planning and the New Hampshire Timberland Owners' Association that modified a risk and reward sharing mechanism approved in an order on February 6, 2004, by the NHPUC. PSNH still is required to obtain various environmental permits, but expects to begin construction later in 2004 following the receipt of those permits. The $75 million project, which will reduce air emissions, will take approximately two years to complete.

The NHPUC's decision approving PSNH's proposal regarding Schiller Station is the subject of an appeal to the New Hampshire Supreme Court by the state's existing wood-fired generating plant owners. Management believes that the appeal will not impair PSNH's ability to proceed with the Schiller Station project.

For further information regarding rate matters associated with business development and capital expenditures, see "Restructuring and Rate Matters," in this Management's Discussion and Analysis.

Regional Transmission Organization

In Order 2000, the FERC required all transmission owning utilities to voluntarily form RTOs or to state why this process has not begun.

On October 31, 2003, the New England Independent System Operator (ISO-NE), along with NU and six other New England transmission companies, filed a proposal with the FERC to create an RTO for New England. On March 24, 2004, the FERC issued an order conditionally accepting the New England RTO proposal. The RTO is intended to strengthen the independent and efficient management of the region's power system while ensuring that customers in New England continue to have the most reliable system possible to facilitate the benefits of a competitive wholesale energy market.

In a separate filing made on November 4, 2003, NU along with six other New England transmission owners requested, consistent with the FERC's pricing policy for RTOs and Order-2000-compliant independent system operators, that the FERC approve a single ROE for regional and local rates that would consist of a proposed 12.8 percent base ROE as well as incentive adders of 0.5 percent for joining a RTO and 1.0 percent for constructing new transmission facilities approved by the RTO.

In its March 24, 2004 order the FERC accepted the proposal for the 0.5 percent incentive adder, but set to hearing the issues of the appropriate base ROE and the clarification as to which facilities the 1.0 percent incentive adder applies. A final ruling regarding these issues is expected in 2005.

Restructuring and Rate Matters

Utility Group: On August 26, 2003, the transmission segment of NU's regulated companies filed its first transmission rate case at the FERC since 1995. In the filing, the companies requested implementation of a formula rate that would allow recovery of increasing transmission expenditures on a timelier basis and that the changes, including a $23.7 million annual rate increase through 2004, take effect on October 27, 2003. The companies requested that the FERC maintain their existing 11.75 percent ROE until a ROE for the New England RTO is established by the FERC. On October 22, 2003, the FERC accepted this filing implementing the proposed rates subject to refund effective on October 28, 2003 and set several issues for hearing.

On June 14, 2004, the transmission segment of NU's regulated companies reached a settlement agreement with the parties to its rate case that allows transmission to implement formula-based rates as proposed with an 11.0 percent ROE until the FERC establishes an ROE for the RTO. The FERC is expected to issue a decision on the settlement agreement in the second half of 2004.

Revenues billed through June 2004 were based on the original proposed ROE of 11.75 percent. The settlement agreement resulted in the recognition of a $1.8 million regulatory liability for the reduction in ROE from 11.75 percent to 11.0 percent and reduced second quarter 2004 earnings by $1.1 million. In addition, a regulatory liability for the collection of costs not yet incurred has also been recognized but had no impact on earnings. This total regulatory liability at June 30, 2004 was approximately $4 million.

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 New England Regional Network Service (RNS) tariff and NU's Local Network Service (LNS) tariff. The RNS tariff, which is administered by ISO-NE, recovers the revenue requirements associated with transmission facilities that are deemed by the FERC to be Pool Transmission

Facilities. This regional rate is reset on June 1st of each year. The LNS tariff which was accepted by the FERC on October 22, 2003, provides for the recovery of NU's total transmission revenue requirements, net of revenues received from other sources, including revenues received under the RNS rates. NU's LNS rate is a formula rate which is also reset on June 1st of each year. Additionally, NU's LNS tariff provides for a true-up to actual costs which ensures that NU recovers its total annual transmission revenue requirements, including the allowed ROE. The calculation of new rates under the LNS tariff, as well as the true-up calculation, are filed with FERC.

Connecticut - CL&P:

Impacts of Standard Market Design: On March 1, 2003, the ISO-NE implemented SMD. As part of SMD, LMP is utilized to assign value and causation to transmission congestion and line losses. Transmission congestion costs represent the additional costs incurred due to the need to run uneconomic generating units in certain areas that have transmission constraints, which prevent these areas from obtaining alternative lower-cost generation. Line losses represent losses of electricity as it is sent over transmission lines.

CL&P was billed $186 million of incremental LMP costs in 2003 by its standard offer service suppliers, including affiliate Select Energy, or by ISO-NE and collected $158 million from its customers. CL&P and its suppliers disputed the responsibility for the $186 million of incremental LMP costs incurred. A settlement agreement was reached to settle the dispute among all the parties involved and was filed with the FERC on March 3, 2004. NU recorded a pre-tax loss in 2003 of approximately $60 million (approximately $37 million after-tax) related to this settlement agreement. The settlement agreement was approved by the FERC on June 28, 2004.

On July 8, 2004, CL&P paid the standard offer service suppliers $83 million as part of the approved settlement agreement, and the remaining $75 million became available to be refunded to CL&P's customers. The method in which the $75 million will be refunded to customers is currently under review by the DPUC with a decision expected in the third quarter of 2004.

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Public Act No. 03-135 and Rate Proceedings: On June 25, 2003, the Governor of Connecticut signed into law Public Act No. 03-135 (the Act) that amended Connecticut's 1998 electric utility industry legislation. The Act required CL&P to file a four-year transmission and distribution plan with the DPUC. On December 17, 2003, the DPUC issued its final decision in the rate case.

CL&P filed a petition for reconsideration of certain items in the rate case on December 31, 2003. Other parties also filed petitions for reconsideration. On January 21, 2004, the DPUC agreed to reconsider CL&P's items and issued a final decision on the reconsideration on August 4, 2004. The final decision allows CL&P to recover approximately $32 million related to these items beginning August 1, 2004. The DPUC has authorized using the existing CTA overrecoveries to recover the approximately $24 million net present value of these additional amounts in lieu of an increase in rates.

The final decision could have a positive pre-tax impact of up to approximately $12 million in 2004. The DPUC's conclusion on streetlighting refund periods and methodologies was also included in the final decision and could significantly reduce the $12 million pre-tax impact. In addition, the impact could also be offset by CL&P's earnings sharing mechanism. Management has not determined the amount of these potential offsets.

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 independent power producer (IPP) over market costs, while the 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 workers protection costs. The GSC allows CL&P to recover the costs of the procurement of energy for standard offer service.

On April 1, 2004, CL&P filed its 2003 CTA and SBC reconciliation with the DPUC. For the year ended December 31, 2003, total CTA revenues and excess GSC revenues as filed exceeded the CTA revenue requirement by $148.3 million. For the same period, SBC revenues as filed exceeded the SBC revenue requirement by $25.5 million. These amounts were recorded as regulatory liabilities on the accompanying condensed consolidated balance sheets.

A final decision in the 2003 CTA and SBC docket was issued on August 4, 2004. In the final decision, the DPUC ordered a refund to customers of $88.5 million over a seven-month period beginning with October 2004 consumption. The DPUC ordered that the SBC rate be reduced to zero effective January 1, 2005. The DPUC also directed CL&P to impute revenue of $2.7 million to customers associated with a previously renegotiated IPP contract. CL&P will likely seek rehearing on this issue, and management cannot predict the outcome of this issue at this time.

In the 2001 CTA and SBC reconciliation filing, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany liability associated with income taxes be excluded from 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. The appeal has been fully briefed and is in the argument phase, and a decision from the Connecticut Superior Court could be rendered by the end of 2004. If the company's request is ultimately granted through court proceedings, then there could be additional amounts due to CL&P from its customers. The 2004 impact of including the deferred intercompany liability in CTA revenue requirements has been a reduction of approximately $19.3 million in revenue.

Connecticut - Yankee Gas:

Rate Case Filing: On July 2, 2004, Yankee Gas filed a rate case with the DPUC to increase retail rates by $26.5 million, or 7.2 percent, effective January 1, 2005. Yankee Gas also requested an authorized ROE of 10.75 percent in the rate case filing. The requested increase in rates results from increased costs of distribution delivery services such as pension and healthcare, as well as additional investments needed to maintain a safe and reliable gas distribution system. Yankee Gas expects a decision from the DPUC on the rate case by the end of 2004 and anticipates that it will underearn its currently authorized 11.0 percent ROE in 2004.

IERM Settlement: On April 29, 2004, Yankee Gas and the OCC filed a settlement agreement that provides for the termination of Yankee Gas' IERM, which tracked the revenue and expenses associated with its system expansion program. The settlement finalizes ratemaking treatment for all Yankee Gas IERM projects and returns Yankee Gas to a traditional capital investment test. A final decision approving the settlement was issued on August 4, 2004. The settlement agreement temporarily lowers the ROE on certain IERM assets to Yankee Gas' debt rate and will not have a material adverse impact on Yankee Gas' net income or financial position.

New Hampshire:

Delivery Rate Case: PSNH's delivery rates were fixed by the "Agreement to Settle PSNH Restructuring" (Restructuring Settlement) until February 1, 2004. Consistent with the requirements of the Restructuring Settlement and state law, PSNH filed a delivery service rate case and tariffs with the NHPUC on December 29, 2003 to increase electricity delivery rates by approximately $21 million, or 2.6 percent, effective February 1, 2004.

On July 14, 2004, PSNH filed with the NHPUC a revenue requirements settlement agreement among several parties, including the NHPUC staff and the OCA. If approved by the NHPUC, the settlement would allow increases in PSNH's delivery rates totaling $3.5 million annually, effective prospectively on October 1, 2004, and an incremental $10 million increase annually effective prospectively on June 1, 2005, for a total rate increase of $13.5 million. On July 29, 2004, PSNH filed with the NHPUC a rate design settlement agreement among several parties, including the NHPUC staff. If approved by the NHPUC, these two settlement agreements would resolve all delivery service rate case issues. A hearing took place on August 3, 2004, and a decision is expected by the end of the third quarter of 2004.

Transition Energy Service: In accordance with the Restructuring Settlement and state law, PSNH files for updated transition energy service (TS) rates annually. The TS rate recovers PSNH's generation and purchased power costs, including a return on PSNH's generation investment. PSNH defers any difference between its TS revenues and the actual costs incurred. On December 19, 2003, the NHPUC issued an order approving a $0.0536 per kWh TS rate effective February 1, 2004 through January 31, 2005.

The December 2003 order also addressed the issue of cost deferrals by requiring a review of TS costs in July 2004 for a possible TS rate change effective August 1, 2004. Accordingly, PSNH filed a petition with the NHPUC on July 1, 2004 requesting a change in the TS rate from the current $0.0536 per kWh to $0.0594 per kWh based on actual costs and underrecoveries incurred to date and updated cost projections. A hearing took place on July 26, 2004, and an order changing

the TS rate to $0.0579 per kWh, effective August 1, 2004 was issued by the NHPUC on August 2, 2004.

SCRC Reconciliation Filing: The Stranded Cost Recovery Charge (SCRC) allows PSNH to recover its stranded costs. On an annual basis, PSNH files with the NHPUC a SCRC reconciliation filing for the preceding calendar year. This filing includes the reconciliation of stranded cost revenues billed with stranded costs, and TS revenues billed with TS costs. The NHPUC reviews the filing, including a prudence review of PSNH's generation operations. The cumulative deferral of SCRC revenues in excess of costs was $175.8 million at June 30, 2004. The 2003 SCRC filing was made on April 30, 2004. Management does not expect the review of the 2003 SCRC filing to have a material effect on PSNH's net income or financial position. Hearings are currently scheduled for October 2004.

Estimated unbilled revenues for PSNH are not considered in the reconciliation of certain billed revenues to incurred costs through rate mechanisms such as the SCRC and the SBC. Accordingly, changes in estimated unbilled revenues due to changes in these charges impact PSNH's earnings in the period of change.

Massachusetts:

Transition Cost Reconciliation: On March 31, 2004, WMECO filed its 2003 transition cost reconciliation with the DTE. This filing reconciled the recovery of generation-related stranded costs for calendar year 2003. The timing of a final decision is uncertain. Management does not expect the outcome of this docket to have a material adverse impact on WMECO's net income or financial position.

NU Enterprises

Business Segments: NU Enterprises aligns its businesses into two business segments, the merchant energy business segment and the energy services business segment. The merchant energy business segment includes Select Energy's wholesale and retail marketing businesses. Also included in this segment are 1,440 MW of generation assets, consisting of 1,293 MW of primarily pumped storage and hydroelectric generation assets at NGC and 147 MW of coal-fired generation at HWP.

In June 2004, the FERC approved a 40-year license extension for NGC's Housatonic hydroelectric generation units in Connecticut. That license covers four conventional stations and one pumped storage station, which together account for approximately 115 MW of capacity.

The energy services business segment includes the operations of SESI, NGS, and Woods Network. SESI performs energy management services for large commercial customers, institutional facilities and the United States government and energy-related construction services. NGS operates and maintains NGC's and HWP's generation assets and provides third-party electrical services. Woods Network is a network design, products and service company.

Outlook: The energy services business segment is not expected to earn any higher than the low end of its previous earnings range of between $4 million and $7 million.

In the second quarter of 2004, Select Energy won 12-month contracts to serve various NSTAR subsidiaries. Under these contracts, Select Energy will serve approximately 1,100 MW and will earn more than $225 million of revenues over the

contract term of July 1, 2004 through June 30, 2005. Select Energy will continue to bid on contracts in 2004 that will take effect in 2004 and beyond. Select Energy's ability to secure a significant amount of wholesale load is a critical factor in NU Enterprises' ongoing profitability. Based upon June 30, 2004 market information, Select Energy's wholesale electric and gas business has already contracted approximately 80 percent of the sales needed to reach its 2004 gross margin targets, assuming satisfactory portfolio management for the remainder of the year.

The retail marketing portion of NU Enterprises' merchant energy business segment has already contracted for more than 75 percent of the business needed to achieve 2004 gross margin targets.

Intercompany Transactions: CL&P's standard offer purchases from Select Energy represented $108.3 million for the three months ended June 30, 2004, compared with $138.9 million during the same period in 2003. Other energy purchases between CL&P and Select Energy totaled $27.7 million for the three months ended June 30, 2004 and $33.2 million during the same period in 2003. Additionally, WMECO's purchases from Select Energy represented $21 million for the three months ended June 30, 2004, compared with $29.2 million during the same period in 2003. These amounts are eliminated in consolidation.

CL&P's standard offer purchases from Select Energy represented $256.8 million for the first six months of 2004, compared with $279.9 million during the same period in 2003. Other energy purchases between CL&P and Select Energy totaled $57.7 million for the first six months of 2004 and $69.2 million during the same period in 2003. Additionally, WMECO's purchases from Select Energy represented $53 million for the first six months of 2004, compared with $68.2 million during the same period in 2003. These amounts are eliminated in consolidation.

NU Enterprises' Market and Other Risks

Overview: For further information on risk management activities, see "Competitive Energy Subsidiaries' Market and Other Risks" in NU's combined report on Form 10-K.

Risk management within Select Energy is organized to address the market, credit and operational exposures arising from the merchant energy business segment, which include: wholesale marketing activities (including limited energy trading for market and price discovery purposes as well as asset optimization) and retail marketing activities. The framework for managing these risks is set forth in NU's risk management policies and procedures, which are periodically reviewed by the NU Board of Trustees.

A significant portion of Select Energy's merchant energy marketing activities is providing electricity to full requirements customers, which are primarily regulated local distribution companies (LDCs) 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 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 the weather. The varying sales volumes could be different than the supply volumes that Select Energy expected to utilize, either

from 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.

The pricing terms of full requirement contracts and of supply contracts can affect the timing of Select Energy's margins. Many full requirements contracts have higher prices in certain months, while certain supply contracts have one price for the entire contract term. Accordingly, Select Energy's margins will tend to be higher in the months when the full requirements contract price is high and lower or could be negative when the full requirements contract price is lower.

Energy Sourcing Activities: In June 2004, Select Energy began purchasing fixed-price electricity and some electricity with prices indexed to gas for 2005 and 2006 in anticipation of winning full requirements contract sales and sales to load-serving entities. Purchasing electricity in advance of winning contracts exposes Select Energy to the risk of electricity price decreases before the full requirement quantities are contracted and before contract prices are known.

To mitigate the risk of electricity price decreases on the fixed-price electricity that was purchased, Select Energy in June 2004 began selling contracts for wholesale natural gas delivery (basis contracts) and natural gas futures and swaps contracts for 2005 and 2006. Select Energy expected that the result of this risk mitigation strategy would be that decreases in the value of the fixed-price electricity purchase contracts would be offset in part by increases in the value of the gas contracts, and vice versa. Select Energy intends to purchase natural gas when quantities and prices of electricity are secured by full requirements contracts or sales contracts with load-serving entities. Natural gas was sold in this risk mitigation strategy due to the high liquidity of the natural gas market compared to the low liquidity of electricity in the Northeast.

The electricity contracts are accounted for on the accrual basis, which will result in earnings recognition when the electricity is delivered in 2005 and 2006. These electricity purchase contracts are expected to be used to meet electricity sales contract requirements, which are a key component of Select Energy's business. Select Energy believes that this electricity will be delivered to its customers.

The use of fair value accounting for the natural gas basis and futures and swaps contracts will expose Select Energy's and NU's earnings to future changes in natural gas prices, which could be significant. This can reasonably be expected to create uncertainty regarding Select Energy's and NU's earnings and earnings trends. The electricity contracts are not expected to be accounted for at fair value, and changes in the value of these contracts, which could be significant, will not impact earnings until the electricity is delivered.

The natural gas basis and futures and swaps contracts are included in non-trading derivative assets and liabilities in the table in Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Merchant Energy Marketing Activities: Select Energy manages its portfolio of wholesale and retail marketing contracts and assets to maximize value while maintaining an acceptable level of risk. There could be significant volatility in the energy commodities markets that could affect merchant energy assets and

contracts between now and when the energy is delivered and the contracts are settled. Accordingly, there can be no assurances that Select Energy will realize the gross margin expected from its wholesale marketing portfolio.

Hedging and Other Non-Trading: For information on derivatives used for hedging purposes and non-trading derivatives, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Wholesale Contracts Defined as "Energy Trading": Energy trading transactions at Select Energy include financial transactions and physical delivery transactions for electricity, natural gas and oil in which Select Energy is attempting to profit from changes in market prices. Energy trading contracts are recorded at fair value, and changes in fair value affect net income.

At June 30, 2004, Select Energy had trading derivative assets of $111.2 million and trading derivative liabilities of $82.9 million, for a net positive position of $28.3 million for the entire trading portfolio. These amounts are combined with other derivatives and are included in derivative assets and derivative liabilities on the accompanying condensed consolidated balance sheets. The increase in both derivative asset and liability amounts from March 31, 2004, relates primarily to price increases. Information regarding non-trading and other derivatives is included in Note 2, "Derivative Instruments," to the consolidated financial statements.

There can be no assurances that Select Energy will realize cash corresponding to the present positive net fair value of its trading positions. Numerous factors could either positively or negatively affect the realization of the net fair value amount in cash. These include the volatility of commodity prices, changes in market design or settlement mechanisms, the outcome of future transactions, the performance of counterparties, and other factors.

Select Energy has policies and procedures requiring all trading positions to be marked-to-market at the end of each business day and segregating responsibilities between the individuals actually trading (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 energy trading contracts are identified and segregated in the table of fair value of contracts at June 30, 2004. A description of each method is as follows: 1) prices actively quoted primarily represent New York Mercantile Exchange futures and options that are marked to closing exchange prices; 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; and 3) prices based on models or other valuation methods primarily include transactions for which specific quotes are not available. Currently, Select Energy has no contracts for which fair value is determined based on a model or other valuation method. Broker quotes for electricity are available through the year 2006. Broker quotes for natural gas are available through 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. However, Select Energy has obtained corresponding purchase or sale contracts for substantially all of the trading contracts that have maturities in excess of one year. Because these contracts are sourced, changes in the value of

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these contracts due to fluctuations in commodity prices are not expected to affect Select Energy's earnings.

As of and for the six months ended June 30, 2004, the sources of the fair value of trading contracts and the changes in fair value of these trading contracts are included in the following tables. Intercompany transactions are eliminated and not reflected in the amounts below.

(Millions of Dollars)	Fair Value of Trading Contracts at June 30, 2004		
Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Maturity in Excess of Four Years
Prices actively quoted	$0.3	$0.1	$ -
Prices provided by external sources	6.3	7.5	14.1
Totals	$6.6	$7.6	$14.1

The fair value of energy trading contracts increased $0.9 million from $27.4 million at March 31, 2004 to $28.3 million at June 30, 2004. The change in the fair value of the trading portfolio is primarily attributable to changes in energy commodity prices during the period. There were no changes in valuation techniques or assumptions in the second quarter of 2004.

	Total Portfolio Fair Value	
(Millions of Dollars)	Three Months Ended June 30, 2004	Six Months Ended June 30, 2004
Fair value of trading contracts outstanding at the beginning of the period	$27.4	$32.5
Contracts realized or otherwise settled during the period	(0.4)	(6.1)
Changes in fair value of contracts	1.3	1.9
Fair value of trading contracts outstanding at the end of the period	$28.3	$28.3

Changing Market: The breadth and depth of the market for energy marketing products in Select Energy's areas of business have been adversely affected by the withdrawal or financial weakening of a number of companies, particularly power marketers, who have historically done significant amounts of business with Select Energy. In general, the market for such products is shorter term in nature with less liquidity, market pricing information is less readily available, and participants are sometimes unable to meet Select Energy's credit standards without providing cash or LOC support. Select Energy is being adversely affected by these factors, and there could be a continuing adverse impact on Select Energy's business lines due to its increasing reliance on business arrangements with a more limited number of counterparties, primarily power generators.

Changes are occurring in the administration of transmission systems in territories in which Select Energy does business. RTOs are being proposed and approved, and other changes in market design are occurring within transmission regions. For example, SMD was implemented in New England on March 1, 2003 and has created both challenges and opportunities for Select Energy. For information regarding the effects of SMD on Select Energy and RTOs, see "Restructuring and Rate Matters," and "Regional Transmission Organization," in this Management's Discussion and Analysis. As the market continues to evolve, there could be additional adverse effects that management cannot determine at this time.

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 written credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial conditions (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, 2004, approximately 79 percent of Select Energy's counterparty credit exposure to wholesale and trading counterparties was cash collateralized or rated BBB- or better. Select Energy received $105 million and $46.5 million of counterparty deposits at June 30, 2004 and December 31, 2003, respectively. Select Energy used these amounts to fund current operations. For further information, see Note 1K, "Counterparty Deposits," to the condensed consolidated financial statements.

Select Energy's Credit: A number of Select Energy's contracts require the posting of additional collateral in the form of cash or LOCs in the event NU's ratings were to decline and in increasing amounts dependent upon the severity of the decline. At NU's present investment grade ratings, Select Energy has not had to post any collateral based on credit downgrades. Were NU's unsecured ratings to decline two to three levels to sub-investment grade, Select Energy could, under its present contracts, be asked to provide approximately $310 million of collateral or LOCs to various unaffiliated counterparties and approximately $97 million to several independent system operators and unaffiliated local distribution companies, which management believes NU would currently be able to provide, subject to the Securities and Exchange Commission (SEC) limits described below. NU's credit ratings outlooks are currently stable or negative, but management does not believe that at this time there is a significant risk of a ratings downgrade to sub-investment grade levels.

On June 30, 2004, the SEC issued an order allowing NU to significantly expand its financial support of NU Enterprises. The new order allows NU through June 30, 2007 to 1) increase its allowable investments in certain of its unregulated businesses, presently 15 percent of its consolidated capitalization as permitted by SEC regulation, by an additional $500 million, 2) increase the limit for its guarantees of all of its competitive affiliates from $500 million to $750 million, and 3) increase its allowable investments in exempt wholesale generators (EWGs) from $481 million to $1 billion. The order will permit NU to fully support the planned level of business activities of Select Energy and its other unregulated businesses. NU has no present plans to significantly expand its EWG portfolio. However, if an investment opportunity becomes available, NU will be able to pursue it within the new allowable EWG investment level.

For further information regarding Select Energy's activities and risks, see Note 2, "Derivative Instruments," and Note 5, "Comprehensive Income," to the condensed consolidated financial statements.

Critical Accounting Policies and Estimates Update

Derivative Accounting, the Election of Normal, and the Use of Hedge Accounting: Most of the contracts comprising Select Energy's wholesale and retail marketing activities are derivatives. The application of derivative accounting under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, is complex and requires management's judgment. Judgment is applied in determining the qualification for the election of the normal purchases and sale exception (and resulting accrual accounting), which includes the conclusions that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting would be terminated and fair value accounting would be applied.

Cash flow hedge contracts that are designated as hedges for contracts for which the company has elected the normal purchases and sales exception can continue to be accounted for as cash flow hedges only if the normal exception for the hedged contract continues to be appropriate. If the normal exception is terminated, then the hedge designation would be terminated at the same time and fair value accounting would be applied.

Accounting for Transmission Revenues Subject to Refund: The $23.7 million transmission rate increase that NU's electric operating companies requested began being billed subject to refund on October 28, 2003. The rate increase was based on a proposed ROE of 11.75 percent, which is unchanged from the ROE included in previous transmission rates and is currently being billed.

Since October 27, 2003, management has evaluated the increase in transmission revenues that has been collected to determine if any amounts are probable of refund to customers in the future.

On June 14, 2004, the transmission segment of NU's regulated companies reached a settlement agreement with the parties to its rate case that allows transmission to implement formula-based rates as proposed with an 11.0 percent ROE until the FERC establishes an ROE for the RTO. The FERC is expected to issue a decision on the settlement agreement in the second half of 2004.

Revenues billed through June 2004 were based on the original proposed ROE of 11.75 percent. The settlement agreement resulted in the recognition of a $1.8 million regulatory liability for the reduction in ROE from 11.75 percent to 11.0 percent and reduced second quarter 2004 earnings by $1.1 million. In addition, a regulatory liability for the collection of costs not yet incurred has also been recognized but had no impact on earnings. This total regulatory liability at June 30, 2004 was approximately $4 million.

A significant portion of NU's transmission businesses' revenue is from charges to NU's distribution businesses. These distribution businesses recover these charges through rates charged to their retail customers. WMECO has a rate tracking mechanism to track transmission expenses charged in distribution rates to the actual amount of transmission charges incurred. The 2004 rates set in the CL&P distribution rate case contained a level of transmission expense sufficient to cover CL&P's anticipated 2004 transmission costs. The June 1, 2005 PSNH rate increase includes revenues in recognition of the transfer of certain assets from transmission rates to distribution rates. Neither CL&P nor PSNH have transmission tracking mechanisms.

Accounting for PSNH Rate Case: PSNH requested that an increase in rates be included in bills starting on February 1, 2004 subject to refund. The NHPUC denied that request but indicated that any rate changes from the rate case would be effective from February 1, 2004 forward.

On July 14, 2004, PSNH filed with the NHPUC a settlement agreement among several parties including the NHPUC staff and the OCA. If approved by the NHPUC, the settlement would result in increases in PSNH's delivery rates effective prospectively on October 1, 2004 and effective prospectively on June 1, 2005.

Unbilled Revenues: Unbilled revenues represent an estimate of electricity or gas delivered to customers that has not been billed. Unbilled revenues are assets on the condensed consolidated balance sheet that become accounts receivable in the following month as customers are billed. Such estimates are subject to adjustment when actual meter readings become available, when changes in estimating methodology occur and under other circumstances.

The Utility Group estimates unbilled revenues monthly using the requirements method. The requirements method utilizes the total monthly volume of electricity or gas delivered to the system and applies a delivery efficiency (DE) factor to reduce the total monthly volume by an estimate of delivery losses in order to calculate total estimated monthly sales to customers. The total estimated monthly sales amount less total monthly billed sales amount results in a monthly estimate of unbilled sales. Unbilled revenues are estimated by applying an average rate to the estimate of unbilled sales. The estimated DE factor can have a significant impact on estimated unbilled revenue amounts.

In accordance with management's policy of testing the estimate of unbilled revenues twice each year using the cycle method of estimating unbilled revenues, testing was performed in the second quarter of 2004. The cycle method uses the billed sales from each meter reading cycle and an estimate of unbilled days in each month based on the meter reading schedule. The cycle method is more accurate than the requirements method when used in a mostly weather-neutral month.

The cycle method testing resulted in adjustments to the estimate of unbilled revenues that had a net positive after-tax earnings impact of $1.5 million in the second quarter of 2004. There were positive after-tax impacts on CL&P, WMECO and Yankee Gas of $1.8 million, $0.9 million, and $0.5 million, respectively, while there was a negative after-tax impact on PSNH of $1.7 million.

Other Matters

Commitments and Contingencies: For further information regarding other commitments and contingencies, see Note 4, "Commitments and Contingencies," to the condensed consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes forward looking statements, which are statements of future expectations and not facts including, but not limited to, statements regarding future earnings, refinancings, regulatory proceedings, the use of proceeds from restructuring, and the recovery of operating costs. Words such as estimates, expects, anticipates, intends, plans, and similar expressions identify forward looking statements. Actual results or outcomes could differ materially as a result of further actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, developments in legal or public policy doctrines, technological developments,

volatility in electric and natural gas commodity markets, and other presently unknown or unforeseen factors.

Website: Additional financial information is available through NU's website at www.nu.com.

RESULTS OF OPERATIONS - NU CONSOLIDATED

The following table provides the variances in income statement line items for the condensed consolidated statements of income for NU included in this report on Form 10-Q for the second quarter of 2004 and the first six months of 2004:

	Income Statement Variances (Millions of Dollars) 2004 over/(under) 2003			
	Second Quarter	Percent	Six Months	P
Operating Revenues:	$195	15%	$449	
Operating Expenses:				
Fuel, purchased and net interchange power	145	19	357	
Other operation	40	17	78	
Maintenance	-	-	10	
Depreciation	5	10	10	
Amortization	5	23	(26)	
Amortization of rate reduction bonds	3	8	7	
Taxes other than income taxes	4	8	8	
Total operating expenses	202	16	444	
Operating income	(7)	(7)	5	
Interest expense, net	4	6	3	
Other income, net	2	(a)	3	
Income before income tax expense	(9)	(20)	5	
Income tax expense	(6)	(37)	1	
Preferred dividends of subsidiary	-	-	-	
Net Income	$ (3)	(11)%	$ 4	

(a) Percent greater than 100.

COMPARISON OF THE SECOND QUARTER OF 2004 TO THE SECOND QUARTER OF 2003

OPERATING REVENUES
Total revenues increased $195 million in the second quarter of 2004, compared with the same period in 2003, due to higher revenues from NU Enterprises ($66 million or $111 million after intercompany eliminations) and higher distribution revenues ($80 million or $77 million after intercompany eliminations) and higher regulated transmission revenues ($9 million or $5 million after intercompany eliminations).

The NU Enterprises' revenues increase is primarily due to higher revenues for the merchant energy segment resulting from higher electric prices ($59 million), higher gas volumes ($15 million) and higher gas prices ($2 million), partially offset by lower electric volumes ($18 million).

The electric distribution revenue increase is primarily due to increases in the standard offer and default service revenues for CL&P, PSNH and WMECO ($74 million) due mainly to rate increases, Federally Mandated Congestion Cost (FMCC) revenues for CL&P ($35 million), and higher sales volume for distribution

revenues ($12 million), partially offset by lower SMD revenue for CL&P ($30 million), lower CL&P Energy Adjustment Clause (EAC) revenue as a result of the end of EAC billings in December 2003 ($9 million) and lower revenues for CL&P and WMECO transition charges ($6 million). Electric retail kWh sales increased by 4.8 percent in the second quarter of 2004.

Transmission revenues were higher due to the October 2003 implementation of the transmission rate case filed at the FERC.

FUEL, PURCHASED AND NET INTERCHANGE POWER

Fuel, purchased and net interchange power expense increased $145 million in the second quarter of 2004, primarily due to higher wholesale costs at NU Enterprises ($60 million or $57 million after intercompany eliminations) and higher purchased power costs for the Utility Group ($40 million or $88 million after intercompany eliminations). The increase for the Utility Group is primarily due to an increase in the standard offer service requirements rates for CL&P ($51 million) and an increase for WMECO ($5 million), partially offset by the 2003 recovery of certain fuel costs ($9 million).

OTHER OPERATION

Other operation expenses increased $40 million in the second quarter of 2004, primarily due to higher competitive business expenses resulting from business growth ($15 million), higher reliability must run costs ($15 million) and higher regulated business administrative and general expenses ($7 million) due to higher pension costs.

DEPRECIATION

Depreciation increased $5 million in the second quarter of 2004 due to higher Utility Group plant balances and higher depreciation rates at CL&P resulting from the distribution rate case decision effective in January 2004.

AMORTIZATION

Amortization increased $5 million in the second quarter of 2004 primarily due to higher Utility Group recovery of stranded costs offset by a decrease in amortization expense resulting from the implementation of the CL&P distribution rate case decision effective in January 2004 ($7 million).

AMORTIZATION OF RATE REDUCTION BONDS

Amortization of rate reduction bonds increased $3 million in the second quarter of 2004 due to the repayment of additional principal as compared to 2003.

TAXES OTHER THAN INCOME TAXES

Taxes other than income taxes increased $4 million in the second quarter of 2004 primarily due to higher Connecticut gross earnings tax as a result of an increase in revenues for NU Enterprises and CL&P, higher local property taxes, higher payroll taxes and higher sales tax.

INTEREST EXPENSE, NET

Interest expense, net increased $4 million in the second quarter of 2004 primarily due to higher interest on long-term debt at NU parent related to a 2003 settlement payment to NU as a result of the interest rate swap for the $263 million fixed-rate senior notes and an increase in long-term debt expense due to the issuance of $150 million of five-year notes at NU parent in June 2003.

OTHER INCOME, NET
Other income, net increased $2 million in the second quarter of 2004 primarily due to the recognition beginning in 2004 of a CL&P procurement fee approved in

the TSO docket decision ($3 million) and a decrease in charitable contributions ($1 million), partially offset by an investment impairment ($3 million).

INCOME TAX EXPENSE
Income tax expense decreased due to lower income before tax expense along with a lower effective tax rate due to the regulatory treatment of taxes by certain Utility Group companies.

COMPARISON OF THE FIRST SIX MONTHS OF 2004 TO THE FIRST SIX MONTHS OF 2003

OPERATING REVENUES
Total revenues increased $449 million in the first six months of 2004, compared with the same period in 2003, due to higher revenues from NU Enterprises ($250 million or $298 million after intercompany eliminations), higher electric distribution revenues ($130 million or $125 million after intercompany eliminations), higher gas distribution revenues ($20 million) and higher regulated transmission revenues ($9 million or $3 million after intercompany eliminations).

The NU Enterprises' revenues increase is primarily due to higher revenues for the merchant energy segment resulting from higher electric prices ($180 million), higher gas volumes ($46 million) and higher gas prices ($12 million), partially offset by lower electric volumes ($11 million).

The electric distribution revenue increase is primarily due to increases in the standard offer and default service revenues for CL&P, PSNH and WMECO ($150 million) due mainly to rate increases, FMCC revenues for CL&P ($75 million), higher sales volume for distribution revenues ($19 million) and higher CL&P retail transmission rates ($13 million), partially offset by lower SMD revenue for CL&P ($29 million), lower CL&P EAC revenue as a result of the end of EAC billings in December 2003 ($21 million) and lower revenues for CL&P and WMECO transition revenues ($16 million). Electric retail kWh sales increased by 3.7 percent in the first six months of 2004. In addition, electric wholesale revenues decreased by $47 million primarily due to lower short-term transactions ($35 million) and the expiration of long-term contracts ($12 million).

The higher gas distribution revenue is primarily due to the increased recovery of gas costs. Firm natural gas sales increased by 3.4 percent in the first six months of 2004 from the same period of 2003.

Transmission revenues were higher due to the October 2003 implementation of the transmission rate case filed at the FERC.

FUEL, PURCHASED AND NET INTERCHANGE POWER
Fuel, purchased and net interchange power expense increased $357 million in the first six months of 2004, primarily due to higher wholesale costs at NU Enterprises ($199 million or $196 million after intercompany eliminations) and higher purchased power costs for the Utility Group ($108 million or $161 million after intercompany eliminations). The increase for the Utility Group is primarily due to an increase in the standard offer service requirements rates for CL&P ($120 million) and an increase for WMECO ($12 million), higher Yankee Gas expenses due to increased gas prices ($21 million), partially offset by the 2003 recovery of certain fuel costs ($21 million), lower wholesale purchases for CL&P ($12 million) and WMECO ($4 million), and lower expenses for PSNH due to lower regulated energy and capacity purchases ($9 million).

OTHER OPERATION
Other operation expenses increased $78 million in the first six months of 2004, primarily due to higher competitive business expenses resulting from business growth ($31 million), higher reliability must run costs ($20 million), higher regulated business administrative and general expenses ($15 million) due to higher pension costs, higher fossil production expense ($3 million), and higher nuclear related expenses as a result of the absence of the 2003 CL&P Millstone use of proceeds docket ($2 million). That docket resulted in the recovery of certain other operation costs and maintenance costs that were expensed in periods prior to 2003. The recovery of these costs through the use of proceeds docket resulted in credits to these accounts in the first quarter of 2003.

MAINTENANCE
Maintenance expenses increased $10 million in the first six months of 2004, primarily due to higher competitive transmission expense ($6 million), the absence of the 2003 positive resolution of the CL&P Millstone use of proceeds docket ($5 million), and higher distribution expense ($3 million), partially offset by lower fossil production expense ($3 million).

DEPRECIATION
Depreciation increased $10 million in the first six months of 2004 due to higher Utility Group plant balances and higher depreciation rates at CL&P resulting from the distribution rate case decision effective in January 2004.

AMORTIZATION
Amortization decreased $26 million in the first six months of 2004 primarily due to lower Utility Group recovery of stranded costs and a decrease in amortization expense resulting from the implementation of the CL&P distribution rate case decision effective in January 2004 ($15 million).

AMORTIZATION OF RATE REDUCTION BONDS
Amortization of rate reduction bonds increased $7 million in the first six months of 2004 due to the repayment of additional principal as compared to 2003.

TAXES OTHER THAN INCOME TAXES
Taxes other than income taxes increased $8 million in the first six months of 2004 primarily due to higher Connecticut gross earnings tax as a result of an increase in revenues for NU Enterprises, CL&P and Yankee Gas, higher local property taxes, higher payroll taxes and higher sales tax.

INTEREST EXPENSE, NET
Interest expense, net increased $3 million in the first six months of 2004 primarily due to the issuance of $150 million of five-year notes at NU parent in June 2003.

OTHER INCOME, NET
Other income, net increased $3 million in the first six months of 2004 primarily due to the recognition beginning in 2004 of a CL&P procurement fee approved in the TSO docket decision ($6 million) and a decrease in charitable contributions ($3 million), partially offset by investment impairments ($6 million).

ITEM 4. CONTROLS AND PROCEDURES (RESTATED)

NU, CL&P, PSNH, and WMECO (collectively, the companies) evaluated the design and operation of their disclosure controls and procedures at June 30, 2004 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 the companies' principal executive officers and principal financial officer, as of the end of the period covered by this report on Form 10-Q/A. The principal executive officers and principal financial officer previously concluded, based on their review, that the companies' disclosure controls and procedures were effective to ensure that information required to be disclosed by the companies in reports that they file under the Exchange Act (i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and (ii) is accumulated and communicated to management, including the principal executive officers and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

On January 26, 2005, subsequent to the June 30, 2004 disclosure control and procedures evaluation, it was determined that there was a material weakness in NU's internal controls over financial reporting. This weakness relates to the discovery, subsequent to the filing of the June 30, 2004 Form 10-Q, of an accounting error in which certain natural gas basis contracts at NU's subsidiary Select Energy were incorrectly accounted for on an accrual basis and certain natural gas futures and swaps contracts were incorrectly accounted for as cash flow hedges. This conclusion is based on the intent of these contracts to hedge electricity contracts, the uncertainty as to if the contracts will result in physical delivery, and the relationship of these contracts to the status of the wholesale natural gas business. The controls and procedures that should have prevented this error will be enhanced and include improved communications, derivative documentation, reporting relationships, and other items.

This error resulted in the restatement of NU's condensed consolidated financial statements as of and for the three and six month periods ended June 30, 2004, and this Form 10-Q/A reflects the change from accrual and hedge accounting to fair value accounting for the contracts described above. Because of these restatements, NU's principal executive officer and principal financial officer, following consultation with and approval of the Audit Committee of the Board of Trustees, have now concluded that NU's disclosure controls and procedures were not effective as of June 30, 2004.

The principal executive officer and principal financial officer of CL&P, PSNH, and WMECO continue to believe that their disclosure controls and procedures were effective to ensure that information required to be disclosed by CL&P, PSNH, and WMECO in reports that they file under the Exchange Act i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and ii) is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There were no significant changes in the companies' internal controls over financial reporting during the quarter ended June 30, 2004 that have materially affected, or are reasonably likely to materially affect the companies' internal controls over financial reporting. Changes to address the material weakness described above were not yet implemented at June 30, 2004.

PART II. OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Listing of Exhibits (NU)

Exhibit No.	Description
31	Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 17, 2005
31.1	Certification of David R. McHale, Senior Vice President and Chief Financial Officer of Northeast Utilities, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 17, 2005
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 March 17, 2005

(b) Reports on Form 8-K:

NU filed a current report on Form 8-K dated May 19, 2004 disclosing:

o The issuance of a news release relating to a decision by the court hearing its merger litigation with Con Edison.

NU and PSNH filed current reports on Form 8-K dated July 14, 2004 disclosing:

o The filing with the NHPUC of a settlement among several parties with regards to its delivery service rate case.

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: March 17, 2005

By /s/ David R. McHale

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