CONNECTICUT LIGHT & POWER CO
Form 10-K
March 01, 2007

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2006

OR

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

For the transition period from ____________ to ____________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street	02-0181050

	Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Northeast Utilities	Common Shares, $5.00 par value	New York Stock Exchange, Inc.

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
The Connecticut Light and Power Company	Preferred Stock, par value $50.00 per share, issuable in series, of which the following series are outstanding:

$1.90	Series	of 1947
$2.00	Series	of 1947
$2.04	Series	of 1949
$2.20	Series	of 1949
3.90%	Series	of 1949
$2.06	Series E	of 1954
$2.09	Series F	of 1955
4.50%	Series	of 1956
4.96%	Series	of 1958
4.50%	Series	of 1963
5.28%	Series	of 1967
$3.24	Series G	of 1968
6.56%	Series	of 1968

Public Service Company of New Hampshire and Western Massachusetts Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

Yes	No
√	

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes	No
	√

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

Yes	No
√	

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer
Northeast Utilities	√		
The Connecticut Light and Power Company			√

Public Service Company of New Hampshire	√
Western Massachusetts Electric Company	√

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

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

The aggregate market value of **Northeast Utilities'** Common Shares, $5.00 Par Value, held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of Northeast Utilities' most recently completed second fiscal quarter (June 30, 2006) was **$3,177,288,120** based on a closing sales price of **$20.67** per share for the 153,714,955 common shares outstanding on June 30, 2006. **Northeast Utilities** holds all of the 6,035,205 shares, 301 shares, and 434,653 shares of the outstanding common stock of **The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company,** respectively.

Indicate the number of shares outstanding of each of the registrants' classes of common stock, as of the latest practicable date:

Company - Class of Stock	Outstanding at January 31, 2007
Northeast Utilities Common shares, $5.00 par value	154,285,480 shares
The Connecticut Light and Power Company Common stock, $10.00 par value	6,035,205 shares
Public Service Company of New Hampshire Common stock, $1.00 par value	301 shares
Western Massachusetts Electric Company Common stock, $25.00 par value	434,653 shares

Documents Incorporated by Reference:

Description	Part of Form 10-K into Which Document is Incorporated
Portions of Annual Reports of the following companies for the year ended December 31, 2006:	
Northeast Utilities	Part II
The Connecticut Light and Power Company	Part II
Public Service Company of New Hampshire	Part II
Western Massachusetts Electric Company	Part II

Portions of the Northeast Utilities Proxy Statement dated March 20, 2007	Part III

GLOSSARY OF TERMS

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

COMPANIES

Acumentrics	Acumentrics Corporation
Boulos	E. S. Boulos Company
CL&P	The Connecticut Light and Power Company
Con Edison	Consolidated Edison, Inc.
CRC	CL&P Receivables Corporation
CYAPC	Connecticut Yankee Atomic Power Company
Funding Companies	CL&P Funding LLC, PSNH Funding LLC, PSNH Funding LLC 2, and WMECO Funding LLC
Globix	Globix Corporation
HWP	Holyoke Water Power Company
Mt. Tom	Mt. Tom Generating Plant
MYAPC	Maine Yankee Atomic Power Company
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company
NU or the company	Northeast Utilities
NU Enterprises or NUEI	NU Enterprises, Inc.
NUSCO	Northeast Utilities Service Company
PSNH	Public Service Company of New Hampshire
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
Utility Group	NU's regulated utilities comprised of the electric distribution and transmission businesses of CL&P, PSNH, WMECO, the generation business of PSNH and the gas distribution business of Yankee Gas.
WMECO	Western Massachusetts Electric Company
Woods Network	Woods Network Services, Inc.
YAEC	Yankee Atomic Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Companies	CYAPC, MYAPC and YAEC
Yankee Gas	Yankee Gas Services Company

MILLSTONE UNITS

Millstone 1	Millstone Unit No. 1, a 660 megawatt nuclear unit completed in 1970; Millstone 1 was sold in March of 2001.
Millstone 2	Millstone Unit No. 2, an 870 megawatt nuclear electric generating unit completed in 1975; Millstone 2 was sold in March of 2001.
Millstone 3	Millstone Unit No. 3, a 1,154 megawatt nuclear electric generating unit completed in 1986; Millstone 3 was sold in March of 2001.

REGULATORS

CSC	Connecticut Siting Council
CDEP	Connecticut Department of Environmental Protection
DOE	United States Department of Energy
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

ABO	Accumulated Benefit Obligation
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
CTA	Competitive Transition Assessment
EDIT	Excess Deferred Income Taxes
EPS	Earnings Per Share
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation No.
FMCC	Federally Mandated Congestion Charges
ISO-NE	New England Independent System Operator or ISO New England, Inc.
ITC	Investment Tax Credits
KWH or kWh	Kilowatt-hour
KV	Kilovolt
LNG	Liquefied Natural Gas
LNS	Local Network Service
LOC	Letter of Credit
MGP	Manufactured Gas Plant
MW	Megawatts
NYMEX	New York Mercantile Exchange
OCC	Office of Consumer Counsel
O&M	Operation and Maintenance
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pensions
PCRBs	Pollution Control Revenue Bonds
Money Pool or Pool	Northeast Utilities Money Pool
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segments excluding the wholesale transmission segment.
Restructuring Settlement	"Agreement to Settle PSNH Restructuring"
RMR	Reliability Must Run
RNS	Regional Network Service
ROE	Return on Equity
RTO	Regional Transmission Operator
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SPE	Special Purpose Entity

UITC	Unamortized Investment Tax Credits
VIE	Variable Interest Entity

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

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SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES

LITIGATION REFORM ACT OF 1995

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (Reform Act), Northeast Utilities (NU) and its reporting subsidiaries are herein filing cautionary statements identifying important factors that could cause NU or its subsidiaries' actual results to differ materially from those projected in forward looking statements (as such term is defined in the Reform Act) made by or on behalf of NU or its subsidiaries in this combined Form 10-K, in any subsequent filings with the Securities and Exchange Commission (SEC), in presentations, in response to questions, or otherwise. Any statements that express or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events, performance or growth (often, but not always, through the use of words or phrases such as estimate, expect, anticipate, intend, plan, believe, forecast, should, could and similar expressions) are not statements of historical facts and may be forward looking. Forward looking statements involve estimates, assumptions and uncertainties that could cause actual results to differ materially from those expressed in the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause NU or its subsidiaries' actual results to differ materially from those contained in forward looking statements of NU or its subsidiaries made by or on behalf of NU or its subsidiaries.

Some important factors that could cause actual results or outcomes to differ materially from those discussed in the forward looking statements include, but are not limited to, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels and timing of capital expenditures, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in reports to the SEC filed by NU and its subsidiaries.

All such factors are difficult to predict, contain uncertainties which may materially affect actual results and are beyond the control of NU or its subsidiaries. Any forward looking statement speaks only as of the date on which such statement is made, and NU and its subsidiaries undertake no obligation to update any forward looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statements. For more information, see "Risk Factors" included in this report.

PART I

Item 1. Business

NORTHEAST UTILITIES

NU, headquartered in Berlin, Connecticut, is a public utility holding company registered with the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005 (PUHCA 2005). NU had been registered with the SEC as a public utility holding company under the Public Utility Holding Company Act of 1935 (PUHCA 1935) until that Act was repealed, effective February 8, 2006. NU is engaged primarily in the energy delivery business, providing franchised retail electric service to approximately 1.9 million customers in 419 cities and towns in Connecticut, New Hampshire and western Massachusetts through three of its wholly-owned subsidiaries; The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), and Western Massachusetts Electric Company (WMECO), and franchised retail natural gas service to approximately 200,000 residential, commercial and industrial customers in 71 cities and towns in Connecticut, through its wholly-owned indirect subsidiary, Yankee Gas Services Company (Yankee Gas).

NU's wholly-owned subsidiary, NU Enterprises, Inc. (NU Enterprises), is in the process of exiting its competitive energy and related businesses and, as of December 31, 2006, had exited substantially all of these businesses.

For information regarding each of the NU system's reportable segments, see Footnote 16, "Segment Information" contained within NU's 2006 Annual Report to Shareholders, which is incorporated into this Form 10-K by reference.

References in this Form 10-K to the "Company," "NU," "we," "our," and "us" refer to Northeast Utilities and its consolidated subsidiaries.

REGULATED ELECTRIC DISTRIBUTION

NU's subsidiaries, CL&P, PSNH and WMECO, are engaged in the distribution of electricity in Connecticut, New Hampshire and western Massachusetts. The following table shows the sources of 2006 electric franchise retail revenues for CL&P, PSNH and WMECO, collectively, based on categories of customers:

	Total NU Operating Companies
Residential	48%
Commercial	39%
Industrial	12%
Other	1%
Total	100%

The actual changes in retail kilowatt-hour (kWh) sales for the last two years and the forecasted retail sales growth estimates for the five-year period 2007 through 2011 for CL&P, PSNH and WMECO, collectively, are set forth below:

	2006 over 2005	2005 over 2004	Forecast 2007-2011 Compound Annual Growth Rate
NU System	-4.0%	2.6%	1.3%

THE CONNECTICUT LIGHT AND POWER COMPANY (CL&P)

Distribution and Sales

CL&P is engaged in the purchase, transmission, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2006, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 towns in Connecticut. CL&P sold all of its generating assets in 2000-2001 as required by state electric industry restructuring legislation, and no longer generates any electricity.

The following table shows the sources of 2006 electric franchise retail revenues for CL&P based on categories of customers:

	CL&P
Residential	48%
Commercial	40%
Industrial	11%
Other	1%
Total	100%

The actual changes in retail kWh sales for the last two years and the forecasted retail sales growth estimates for the five-year period 2007 through 2011 for CL&P are set forth below:

	2006 over 2005	**2005 over 2004**	**Forecast 2007-2011 Compound Annual Growth Rate**
CL&P	-4.9%	3.0%	1.1%

Rates

CL&P's retail rates are subject to regulation by the Connecticut Department of Public Utility Control (DPUC). CL&P's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. Connecticut utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to cover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

CL&P's retail rates include delivery service, which includes distribution, transmission, conservation, renewables, competitive transition assessment and other charges that are assessed on all customers, and electric generation service, which includes the costs of power supply it purchases for customers that do not choose to be served by a competitive retail supplier.

CL&P has also received regulatory orders allowing it to recover all or substantially all of its prudently incurred "stranded" costs, which are pre-restructuring expenditures incurred, or commitments made for future expenditures, on behalf of customers with the expectation such expenditures would continue to be recoverable in the future through rates. CL&P has financed a significant portion of its stranded costs through the issuance of rate reduction certificates (securitization) and is recovering the costs of securitization through the Competitive Transition Assessment (CTA) component of its rates. As of December 31, 2006, CL&P had fully recovered all stranded costs, except those being recovered through securitization, ongoing independent power producer costs, costs associated with the ongoing decommissioning of the Maine Yankee, Connecticut Yankee and Yankee Rowe nuclear units, and annual decontamination and decommissioning costs payable under federal law.

Under state law, all of CL&P's customers are now able to choose their energy suppliers, with CL&P furnishing service to those customers who do not choose a competitive supplier. Beginning January 1, 2007, this service is termed "Standard Service" for customers that are less than 500 kW of demand and "Supplier of Last Resort Service" for customers who are not eligible for Standard Service.

Most of CL&P's customers have continued to buy their power from CL&P at these rates but CL&P is experiencing accelerating customer migration to alternative suppliers, with the movement concentrated among the larger customers. As of December 31, 2006, approximately 40,000 customers out of 1.2 million, representing approximately 9% of December load, had selected competitive energy supply.

On December 8, 2006, the DPUC approved CL&P's Standard Service rates, effective as of January 1, 2007. The new Standard Service rates reflect an increase of approximately 7.8% and are expected to remain effective until July 1, 2007 when these rates will likely be adjusted to reflect additional supplier bids received for 2007 and updated wholesale transmission costs. Supplier of Last Resort rates will vary, and total bills for those customers increased by 19% on January 1, 2007. On August 4, 2006, CL&P notified the DPUC that it intended to postpone filing a distribution rate case until mid-2007, and the case, when filed, would target new rates to be effective in early 2008.

As a result of Connecticut legislation passed in July 2005, CL&P filed for a transmission adjustment clause on August 1, 2005 with the rate tracking mechanism to be effective on July 6, 2005. On December 20, 2005, the DPUC approved the tracking mechanism, which provides for semi-annual adjustments in January and July of each year. CL&P adjusts its retail transmission rates on a regular basis, thereby recovering all of its retail transmission expenses on a timely basis.

Sources and Availability of Electric Power Supply

As noted above, CL&P owns no generation assets and purchases its energy requirements from a variety of competitive sources through periodic requests for proposals (RFPs). On June 21, 2006, the DPUC approved a plan for CL&P to issue RFPs periodically for periods of up to three years to layer Standard Service full requirements supply contracts in order to mitigate market volatility for its residential and lower use commercial and industrial customers. Additionally, the DPUC approved the issuance of RFPs for Supplier of Last Resort service for larger commercial and industrial customers every six months. Previously, all of CL&P's residential, commercial and industrial requirements, regardless of customer size, were bid together. The DPUC's decision also provides for enhanced access to the RFP materials, bids and other data during and after the RFP process.

In September of 2006, CL&P received bids and awarded contracts for a portion of Standard Service loads for 2007 and 2008. CL&P also received bids and awarded contracts for a portion of Standard Service loads for 2007 through 2009 in October of 2006. CL&P will receive bids in 2007 for Standard Service for remaining 2007 load requirements and for some load requirements in 2008 and 2009. CL&P also received bids and awarded contracts in September of 2006 for its Supplier of Last Resort Service for its larger commercial and industrial customers for January through June of 2007. None of CL&P's suppliers for 2007 and beyond are affiliated with CL&P. CL&P is fully recovering all of the payments it is making to those suppliers through DPUC-approved rates billed to customers, and has financial assurances from each supplier or from a parent or affiliate of each supplier to protect CL&P from loss in the event any of the suppliers encounters financial difficulties.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE (PSNH)

Distribution and Sales

PSNH is primarily engaged in the generation, purchase, transmission, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2006, PSNH furnished retail franchise electric service to approximately 487,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 megawatt (MW) of electricity generation assets, with a current claimed capability representing winter rates, of approximately 1,170 MW. Included among these generating assets is a 50 MW wood-burning generating unit in Portsmouth, New Hampshire, which was converted from a coal-burning unit and went into full operation in December, 2006.

The following table shows the sources of 2006 electric franchise retail revenues based on categories of customers:

	PSNH
Residential	43%
Commercial	41%
Industrial	15%
Other	1%
Total	100%

The actual changes in retail kWh sales for the last two years and the forecasted retail sales growth estimates for the five-year period 2007 through 2011 for PSNH are set forth below:

	2006 over 2005	2005 over 2004	Forecast 2007-2011 Compound Annual Growth Rate
PSNH	-1.3%	1.9%	2.3%

Rates

Default Energy Service (ES): PSNH's retail rates are subject to regulation by the New Hampshire Public Utilities

Commission (NHPUC). PSNH files for approval of updated ES rates periodically with the NHPUC to ensure timely recovery of its costs. The ES rate recovers PSNH's generation and purchased power costs, including a return on equity (ROE) on PSNH's generation assets. PSNH defers for future recovery or refund any difference between its ES revenues and the actual costs incurred.

On December 2, 2005, the NHPUC issued a decision lowering PSNH's allowed generation ROE to 9.62% retroactive to an effective date of August 1, 2005. This decrease in allowed generation ROE lowers PSNH's net income by approximately $1.5 million annually based on the current level of generation assets.

On January 20, 2006, the NHPUC approved new ES rates of $0.0913 per kWh for the eleven month period February 1, 2006 through December 31, 2006. In its order, the NHPUC also allowed PSNH to implement deferred accounting treatment for the new accounting associated with asset retirement obligations. On June 29, 2006, the NHPUC decreased the ES rate to $0.0818 per kWh based upon updated cost information for the period July 1, 2006 through December 31, 2006.

On September 8, 2006, PSNH filed a petition with the NHPUC requesting a change in its ES rate for the 12-month period January 1, 2007 through December 31, 2007. On December 15, 2006, the NHPUC issued an order approving the filed ES 2007 rate of $0.0859 per kWh. As in previous NHPUC ES rate orders, there is a provision to update the ES rate during the 2007 rate year based upon updated actual and projected cost information.

Delivery Service (DS) Rates: On May 30, 2006, PSNH filed a petition with the NHPUC requesting a permanent increase in its delivery service (DS) rate of approximately $50 million, the approval of a transmission cost tracking mechanism, and a decrease in its stranded cost charge and energy charge to reflect the completed recovery of certain stranded costs and changes in PSNH's actual costs to provide transition energy service. On June 29, 2006, the NHPUC approved a temporary DS rate increase of $24.5 million, effective on July 1, 2006. This temporary rate increase will be reconciled to the allowed permanent rate increase effective back to the July 1, 2006 date. On November 17, 2006, PSNH updated its permanent DS rate filing, increasing the request to $60 million, due primarily to updated rate base projections and higher reliability spending.

On February 26, 2007, PSNH filed a settlement agreement it reached with the NHPUC staff and the Office of Consumer Advocate related to its rate case filing. The settlement agreement includes, among other things, a transmission cost tracking mechanism, effective on July 1, 2006, to be reset annually, and an allowed ROE of 9.67 percent. The allowed generation ROE of 9.62 percent was unaffected. The settlement provides for a $37.7 million estimated annualized increase ($26.5 million for distribution and $11.2 million estimated for transmission) beginning July 1, 2007 in addition to the $24.5 million temporary increase that was effective on July 1, 2006. An additional delivery revenue increase of approximately $3 million would take effect on January 1, 2008, with a final estimated rate decrease of approximately $9 million scheduled for July 1, 2008. The increased revenues will enable PSNH to fund a $10 million annual Reliability Enhancement Program and more accurately fund its Major Storm Cost Reserve. The increased revenues also include approximately $9 million related to additional revenues for the period July 1, 2006 through June 30, 2007 that will be recovered over one year. The NHPUC has scheduled hearings on the proposed settlement beginning in March 2007, with a final decision expected by late spring of 2007.

Stranded Cost Recovery Charge (SCRC): Under New Hampshire law, the SCRC allows PSNH to recover its stranded costs. PSNH has financed a significant portion of its stranded costs through securitization by issuing rate reduction bonds. It recovers the securitization costs, which are known as Part 1 costs, through the SCRC rate.

On an annual basis, PSNH files with the NHPUC a SCRC/ES reconciliation filing for the preceding calendar year. This filing includes the reconciliation of SCRC revenues and costs and the ES revenues and costs. The NHPUC reviews the filing, including a prudence review of the operations within PSNH's generation business segment. On October 25, 2006, PSNH, the NHPUC Staff and the Office of Consumer Advocate filed a settlement agreement with the NHPUC which resolved all outstanding issues associated with PSNH's 2005 reconciliation. After hearings, the NHPUC issued its order approving the settlement agreement. The terms of the settlement had virtually no impact on PSNH's financial position.

In accordance with the "Agreement to Settle PSNH Restructuring", PSNH is required to periodically recalculate its SCRC once its non-securitized (Part 3) costs are fully recovered. PSNH fully recovered its remaining Part 3 costs in June 2006, and an initial reduction of the SCRC from $0.0355 per kWh to $0.0155 per kWh was approved by the NHPUC on June 29, 2006 and effective July 1, 2006.

On September 22, 2006, PSNH filed a petition with the NHPUC requesting a decrease in its SCRC for the period January 1, 2007 through December 31, 2007 based upon market conditions and the NHPUC's decision regarding the duration of certain independent power producer agreements. On November 17, 2006, PSNH filed a revised petition with the NHPUC on the SCRC rate which was approved by the NHPUC on December 15, 2006 and resulted in a reduction in the SCRC rate to $0.0130 per kWh, effective in 2007.

Although PSNH's customers are able to choose competitive energy suppliers, PSNH has experienced almost no customer migration to date.

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

Sources and Availability of Electric Power Supply

During 2006, about 75% of PSNH load was met through owned generation and long-term power supply contracts. The remaining 25% of PSNH's load was met by short-term (less than one year) purchases and spot purchases from the New England Independent System Operator (ISO-NE) wholesale market. For 2007, PSNH expects to meet its load in a similar manner to 2006.

WESTERN MASSACHUSETTS ELECTRIC COMPANY (WMECO)

Distribution and Sales

WMECO is engaged in the purchase, transmission, delivery and sale of electricity to residential, commercial and industrial customers. At December 31, 2006, WMECO furnished retail franchise electric service to approximately 210,000 retail customers in 59 cities and towns in Massachusetts. WMECO sold all of its generating assets in 2000-2001 as required by state electric industry restructuring legislation, and no longer generates any electricity.

The following table shows the sources of 2006 electric franchise retail revenues based on categories of customers:

	WMECO
Residential	56%
Commercial	32%
Industrial	11%
Other	1%
Total	100%

The actual changes in retail kWh sales for the last two years and the forecasted retail sales growth estimates for the five-year period 2007 through 2011 for WMECO are set forth below:

	2006 over 2005	**2005 over 2004**	**Forecast 2007-2011 Compound Annual Growth Rate**
WMECO	-4.2%	1.4%	0.1%

Rates

Under state law, all of WMECO's customers are now able to choose their energy suppliers, with WMECO furnishing "basic service" to those customers who do not choose a competitive supplier. Most of WMECO's residential and smaller customers have continued to buy their power from WMECO at these rates. A greater proportion of larger commercial and business customers have opted for a competitive retail supplier. As of December 31, 2006, approximately 11,000 out of nearly 210,000 customers have elected this option, representing about 43% of the energy delivered by WMECO.

WMECO's retail rates are subject to regulation by the Massachusetts Department of Telecommunications and Energy (DTE). WMECO's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. Massachusetts utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to cover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

WMECO collects its transmission costs through a transmission adjustment clause. The DTE approved the tracking mechanism in January 2002, which provides for annual adjustments, thereby allowing WMECO to recover all of its retail transmission expenses on a timely basis.

WMECO has also received regulatory orders allowing it to recover all or substantially all of its prudently incurred "stranded" costs. WMECO has financed a portion of its stranded costs through securitization by issuing rate reduction certificates and is recovering the costs of securitization through rates.

Rate Case Settlement: On December 14, 2006, the DTE approved a rate settlement agreement (the Settlement) between WMECO, the Attorney General of the Commonwealth of Massachusetts, the Low-income Energy Affordability Network, and the Associated Industries of Massachusetts which was filed with the DTE in lieu of a base rate proceeding. The Settlement provides a $1.0 million increase in WMECO's distribution rates effective January 1, 2007 and an additional increase in distribution rate of $3.0 million effective January 1, 2008. Also included in the Settlement are cost tracking mechanisms for pension and other postretirement benefit costs, uncollectible amounts related to energy costs, and recovery of certain capital improvements and related expenses needed for system reliability. The Settlement includes an earnings sharing mechanism that will equally share with customers any earnings in excess of an actual ROE of 12% and any shortfall below an actual ROE of 8% during the two-year settlement period. The determination of any excess or shortfall would be done annually, with any such excess being recorded as a regulatory liability and any such shortfall being recorded as a regulatory asset.

Annual Rate Change Filing: On November 30, 2006, WMECO made its 2006 annual rate change filing. Because the timing of this filing coincided with WMECO's rate case settlement decision described above, the DTE combined WMECO's annual rate change filing with its rate case settlement compliance filing. The combined filing implements the $1 million distribution rate increase and associated cost tracking mechanisms as allowed under its rate case settlement agreement and reflects rate increases for 2007 default service supply. On average, total rates increased 17.8 %. On December 29, 2006, the DTE approved the rates effective January 1, 2007.

Sources and Availability of Electric Power Supply

As noted above, WMECO owns no generation assets and purchases its energy requirements from a variety of competitive sources through periodic RFPs. For basic service power supply, WMECO makes periodic market solicitations consistent with DTE regulations. During 2006, WMECO entered into power purchase agreements to meet its entire basic service supply obligation, other than to its largest customers, for the period January 1, 2007 through June 30, 2007 and for 50% of its obligation, other than to these large customers, for the second-half of 2007. WMECO has entered into short-term power purchase agreements to meet its entire basic service supply obligation for large customers for the period January 1, 2007 through March 2007 and April 1 through June 30, 2007. An RFP will be issued quarterly in 2007 for the remainder of the obligation for large customers and semi-annually for non-large customers. For 2006, WMECO entered into agreements for either three or twelve-month periods.

LICAP AND FCM DEVELOPMENT

On March 6, 2006, ISO-NE and a broad cross-section of critical stakeholders from around the region, including CL&P and PSNH, filed a comprehensive settlement agreement at the FERC proposing a forward capacity market (FCM) in place of the previously proposed locational installed capacity (LICAP), an administratively determined electric generation capacity pricing mechanism. The settlement agreement provided for a fixed level of compensation to generators from December 1, 2006 through May 31, 2010 without regard to location in New England, and annual forward capacity auctions, beginning in 2008, for the 1-year period ending on May 31, 2011, and annually thereafter. According to preliminary estimates, FCM would require our utility subsidiaries to pay approximately the following amounts from December 1, 2006 through December 31, 2009: CL&P - $470 million; PSNH - $80 million; and WMECO - $100 million. CL&P, PSNH and WMECO expect to recover these costs from their ratepayers. On June 16, 2006, the FERC accepted the settlement agreement. Several parties sought rehearing of this issue by the FERC, which was denied on October 31, 2006. On December 1, 2006 the Settlement Agreement was implemented and the payment of fixed compensation to generators began.

For more information regarding CL&P, WMECO and PSNH state regulatory matters, see "Utility Group Regulatory Issues and Rate Matters" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which is incorporated into this Form 10-K by reference.

REGULATED ELECTRIC TRANSMISSION

General

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

Rates

Most of NU's wholesale transmission revenues are collected through a combination of ISO-NE FERC Electric Tariff No. 3, Open Access Transmission Tariff (RNS), and Schedule 21 - NU (LNS) to that tariff. The RNS (or regional network service) tariff is administered by ISO-NE and is billed to all New England transmission users. RNS recovers the revenue requirements associated with facilities that are deemed to provide a regional benefit, or pool transmission facilities. The RNS rate is reset on June 1^{st} of each year and NU collects approximately 75 percent of its wholesale transmission revenues under its RNS tariff. NU's LNS (or local network service) rate is reset on January 1^{st} and June 1^{st} of each year and provides for a true-up to actual costs, which ensures that NU's transmission business recovers its total transmission revenue requirements, including the allowed ROE.

FERC ROE Decision

On October 31, 2006, the FERC issued its decision on the specific ROE and incentives for New England transmission owners. The FERC set the base ROE (before incentives) at 10.2% for the historical locked-in period of February 1, 2005 (when the New England RTO was activated) to October 31, 2006. Effective November 1, 2006, the FERC also added a 70 basis point adjustment to reflect upward pressure on the 10-year treasury rate, bringing the going forward base ROE to 10.9%. In addition, the FERC approved a 50 basis point adder for joining an RTO and approved a 100 basis point adder for all new transmission investment where the projects have been identified as necessary by the ISO-NE regional planning process. Both ROE adders for certain projects are retroactive to February 1, 2005.

On a going forward basis, our transmission capital program is largely comprised of regional infrastructure that is included within the regional planning process. Over 90% of our projected $2.5 billion capital program for 2007 through 2011 is expected to be in this category, and therefore is expected to earn at the RNS rate's 12.4% ROE.

The following is a summary of the ROEs for the applicable periods and tariffs:

	LNS	RNS	New ISO-NE Approved
RTO - February 1, 2005 to October 31, 2006	10.2% (base)	10.7% (10.2% plus 0.5% for RTO membership)	11.7% (10.7% plus 1.0% adder)
RTO - November 1, 2006 forward	10.9% (10.2% base plus 0.7% adjustment)	11.4% (10.9% plus 0.5% for RTO membership)	12.4% (11.4% plus 1.0% adder)

On November 30, 2006, the New England Transmission Owners jointly filed a rehearing request for an additional 30 basis points for the base ROE to correct what appears to be an error in the FERC's base ROE calculation. Additionally, several New England Public Utilities Commissions, Consumer Counsels and Municipals have filed a rehearing request challenging the 70 basis point Treasury rate adder and the 100 basis point adder for new regional transmission investment.

On December 29, 2006, FERC issued a tolling order stating that it accepted the various rehearing requests and intends to act on them. This order allows the regional transmission owners to collect tariffs per the ROE order subject to refund. The order did not include an action date and until FERC takes some action on the rehearing requests, parties cannot bring an appeal to court.

Other Rate Matters

Effective on February 1, 2006, NU began including 50% of construction work in progress (CWIP) for its four major southwest Connecticut transmission projects in its LNS rate for transmission service. The new rates allow NU to collect 50% of the construction financing expenses while these projects are under construction.

On July 20, 2006, the FERC issued final rules promoting transmission investment through pricing reform that included up to 100% of CWIP in rate base, accelerated book depreciation, and higher ROEs for belonging to an RTO, among others. The final rule identifies specific incentives the FERC will allow when justified in the context of specific rate applications. The burden remains on the applicant to illustrate through its filing that the incentives requested are just and reasonable and the project involved increases reliability or decreases congestion costs. The FERC reaffirmed these incentives in its order on rehearing issued on December 22, 2006.

On July 28, 2006, the FERC approved CL&P's proposal to allocate costs associated with the Bethel to Norwalk transmission project that are determined to be localized costs to all customers in Connecticut, as all of Connecticut will benefit from the reduction in congestion charges associated with the project. There are three load serving entities in Connecticut: CL&P, United Illuminating (UI) and the Connecticut Municipal Electrical Energy Cooperative. These customers would pay their allocated shares of the localized costs on a projected basis commencing on June 1, 2006, subject to true-up based on actual costs. On December 26, 2006, FERC rejected a request by UI for rehearing of this decision. On February 23, 2007, UI appealed the FERC's orders to the D.C. Circuit Court of Appeals.

On September 22, 2006, ISO-NE issued its determination letter with regard to CL&P's February 3, 2006 revised transmission cost allocation application for the Bethel to Norwalk transmission project. The decision found that $239.8 million of the total estimated cost of $357.2 million qualifies as pool-supported pool transmission facilities costs, indicating $117.4 million of total estimated costs that are localized. CL&P has decided not to challenge ISO-NE's cost allocation decision.

Transmission Projects

Our capital expenditures, including cost of removal, the allowance for funds used in construction, and the capitalized portion of pension expense or income, on transmission projects in 2006 totaled approximately $465.5 million, most of it at CL&P. For 2006, CL&P's transmission capital expenditures totaled $415.6 million, PSNH's transmission capital expenditures totaled $36.1 million and WMECO's transmission capital expenditures totaled $13.0 million.

CL&P's transmission capital expenditures were primarily on four major transmission projects in southwest Connecticut: 1) the completed Bethel to Norwalk project, 2) a 69-mile Middletown to Norwalk 115kV/345kV transmission project, 3) a related two-cable 115 kV underground project between Norwalk and Stamford, Connecticut (Glenbrook Cables), and 4) the replacement of the existing 138 kV cable between Connecticut and Long Island. Each of these projects has received approval from the Connecticut Siting Council (CSC) and ISO-NE.

The Bethel to Norwalk project, a 21-mile, 345 kV project between Bethel, Connecticut and Norwalk, Connecticut, was completed in the fourth quarter of 2006 at a cost of approximately $340 million, approximately $10 million below budget, and was fully energized and placed into service on October 12, 2006.

CL&P has commenced site work on the 69-mile 345 kV transmission line from Middletown to Norwalk, to be jointly built by UI and CL&P. The project still requires some CSC review of certain detailed construction plans. Although this project is currently expected to be completed by the end of 2009, opportunities to optimize schedule performance may result in an earlier completion date. This project is currently 16 percent complete and CL&P's portion of this project is estimated to cost approximately $1.05 billion. At December 31, 2006, CL&P has capitalized $186.4 million associated with this project.

Construction has begun on the Glenbrook Cables Project, two 9-mile 115 kV underground transmission lines between Norwalk and Stamford, which is expected to cost approximately $183 million. This project is currently approximately 20% complete and on schedule for a December 2008 in-service date. As of December 31, 2006, CL&P had capitalized $40.9 million associated with this project.

Design and engineering work on the CL&P and the Long Island Power Authority (LIPA) plans to replace a 138 kV undersea electric transmission line between Norwalk, Connecticut and Northport - Long Island, New York, is complete, and cable manufacturing commenced in mid-January, 2007. CL&P and LIPA each own approximately 50% of the line. CL&P's portion of the project is estimated to cost $72 million. Final permits are expected by mid-2007 with marine construction activities commencing in October, 2007. The projected in service date remains in 2008. Through December 31, 2006, CL&P had capitalized $16.9 million associated with this project.

In December 2006, CL&P completed construction and commenced commercial operation of a new substation in Killingly, Connecticut which will improve CL&P's 345 kV and 115 kV transmission systems in northeast Connecticut. As of December 31, 2006 CL&P had capitalized $25.9 million associated with this project, and estimates the final cost to be approximately $29 million, slightly below the budget of $32 million.

As part of a larger regional system plan, NU, ISO-NE and National Grid have begun planning upgrades to the transmission system connecting Massachusetts, Rhode Island and Connecticut in a comprehensive study called the Southern New England Transmission Reinforcement (SNETR) Project. That study has led to the identification of three interdependent NU projects that work together to address the region's transmission needs -- the Greater Springfield Reliability Project, the Central Connecticut Reliability Project, and the Interstate Reliability Project. Together, these three projects, along with National Grid's Rhode Island Reliability project, are referred to as the New England East-West Solution (NEEWS). NU and National Grid have not yet completed a detailed estimate of the total cost for these upgrades, but NU estimates that its share of these projects may range from $1.1 billion to $1.4 billion of which approximately $710 million is included in its $2.5 billion 2007 through 2011 capital budget. NU and National Grid have entered into a formal agreement to plan and permit these projects.

We project total transmission capital expenditures for the period 2007-2011 to be approximately $2.5 billion. Of that amount, we project that CL&P will spend approximately $2 billion, PSNH will spend approximately $246 million, and WMECO will spend approximately $200 million.

Transmission Rate Base

Under NU's FERC-approved tariffs, transmission projects enter rate base once they enter commercial operation. Additionally, 50 percent of NU's capital expenditures on its four major transmission projects in southwest Connecticut enter rate base during the construction period with the remainder entering rate base once the projects are complete. At the end of 2006, NU's estimated transmission rate base was $1.1 billion, including approximately $840 million at CL&P, $140 million at PSNH and $75 million at WMECO. NU's total transmission rate base was approximately $600 million at the end of 2005. The company forecasts that its total transmission rate base will grow to approximately $1.4 billion at the end of 2007, $1.9 billion at the end of 2008, $2.6 billion at the end of 2009, $2.8 billion at the end of 2010, and $3 billion at the end of 2011. This increase in transmission rate base is driven by the need to improve the capacity and reliability of NU's regulated transmission system.

A summary of projected year end transmission rate base by Utility Group company is as follows (millions of dollars):

Company	**2007**	**2008**	**2009**	**2010**	**2011**
CL&P	$1,173	$1,512	$2,117	$2,218	$2,461
PSNH	175	276	282	335	325
WMECO	80	132	173	208	239
Totals	$1,428	$1,920	$2,572	$2,761	$3,025

For more information regarding Regulated Transmission matters, see "Transmission Rate Matters and FERC Regulatory Issues" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which is incorporated into this Form 10-K by reference.

REGULATED GAS OPERATIONS

Yankee Energy System, Inc. (Yankee) is the holding company of Yankee Gas and two active non-utility subsidiaries, NorConn Properties, Inc., which holds certain minor properties and facilities of Yankee and its subsidiaries, and Yankee Energy Financial Services Company, which was in the business of providing Yankee Gas customers and other energy end-users with financing primarily for energy equipment installations, but which is in the process of winding up its business operations.

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 200,000), and size of service territory (2,088 sq. miles). Total throughput (sales and transportation) for 2006 was 45.2 BcF. Yankee Gas provides firm gas sales service to customers who require a continuous gas supply throughout the year, such as residential customers who rely on gas for their heating, hot water and cooking needs. Yankee Gas also offers firm transportation service to its commercial and industrial customers as well as interruptible transportation and interruptible gas sales service to those certain commercial and industrial customers that have the capability to switch from natural gas to an alternative fuel on short notice. Yankee Gas can interrupt service to these customers during peak demand periods or at any other time to maintain distribution system integrity. Yankee Gas offers firm and interruptible transportation services to customers who purchase gas from sources other than Yankee Gas. In addition, Yankee Gas performs gas sales, gas exchanges and capacity releases to other market participants to reduce its overall gas expense.

Yankee Gas earned $11.9 million on total gas operating revenues of approximately $454 million for the full-year 2006, compared with earnings of $17.3 million for full-year 2005. Yankee Gas earnings were lower due primarily to an 11.2 percent decline in firm natural gas sales in 2006, compared with 2005, largely the result of milder weather in 2006. The following table shows the sources of 2006 total gas operating revenues:

	Yankee Gas
Residential	47%
Commercial	28%
Industrial	23%
Other	2%
Total	100%

For more information regarding Yankee Gas' financial results, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data," which includes Note 16, "Segment Information," within the notes to the consolidated financial statements, contained within NU's Annual Report to Shareholders, which is incorporated into this Form 10-K by reference.

Although Yankee Gas is not subject to the FERC's jurisdiction, the FERC does have limited oversight over certain intrastate gas transportation that Yankee Gas provides. In addition, the FERC regulates the interstate pipelines serving Yankee Gas' service territory.

Yankee Gas is subject to regulation by the DPUC, which, among other things, has jurisdiction over rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities.

On December 29, 2006, Yankee Gas filed a request with the DPUC for a rate increase of approximately $67.8 million effective July 1, 2007. The request proposes to recover the costs of constructing the liquefied natural gas (LNG) storage facility (described below) and the increased costs of providing distribution and delivery service. Yankee Gas expects that this increase will be offset by savings in commodity and pipeline-related savings for a net revenue increase of approximately $37.2 million or 8.4% above current rates.

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

The DPUC has hired a consulting firm which has begun an audit of Yankee Gas' previously recovered PGA costs. Yankee Gas expects that the audit will be completed in the first half of 2007. Management believes the unbilled sales and revenue adjustments and resultant charges to customers through the PGA clause for both periods were appropriate. Based on the facts of the case and the supplemental information provided to the DPUC, Yankee Gas believes the appropriateness of the PGA charges to customers for the time period under review will be approved, and has not reserved for any loss.

Yankee Gas is constructing an LNG facility in Waterbury, Connecticut capable of storing the equivalent of 1.2 billion cubic feet of natural gas. It is expected to be put into service by mid-2007 in time for the 2007-2008 heating season at a total cost of approximately $108 million. At December 31, 2006, the project was approximately 89% complete and Yankee Gas had capitalized $95.3 million related to this project. In 2006, Yankee Gas also capitalized $41 million related to reliability improvements, new customer connections and other initiatives.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

Our capital expenditures for 2006, including cost of removal, allowance for funds used during construction and the capitalized portion of pension expense or income, totaled approximately $946 million, of which approximately $908 million was expended by CL&P, PSNH, WMECO and Yankee Gas. Approximately $466 million was spent by CL&P, PSNH and WMECO on transmission projects. The capital expenditures of these companies in 2007 are estimated to total approximately $1.2 billion. Of such total amount, approximately $860 million is expected to be expended by CL&P, $211 million by PSNH, $50 million by WMECO and $62 million by Yankee Gas. This construction program data includes all anticipated costs necessary for committed projects and for those reasonably expected to become committed projects in 2007, regardless of whether the need for the project arises from environmental compliance, reliability requirements or other causes. The construction program's main focus is maintaining, upgrading and expanding the existing electric transmission and distribution system and natural gas distribution system, including the construction of Yankee Gas' LNG facility. We expect to evaluate our needs beyond 2007 in light of future developments, such as restructuring, industry consolidation, performance and other events. If current plans are implemented on schedule, we would likely require additional external financing at the subsidiary level to construct these projects.

In 2006, CL&P's transmission capital expenditures totaled $416 million. In 2007, CL&P projects transmission capital expenditures of approximately $590 million. During the period 2007 through 2011, CL&P plans to invest approximately $2 billion in transmission projects, including $860 million to construct the Middletown to Norwalk transmission line, and $142 million for the Glenbrook Cables Project. Approximately $55 million will be invested during this period to pay for CL&P's share of replacing the 138 kV transmission line beneath Long Island Sound jointly owned by CL&P and LIPA. If all of the transmission projects are built as proposed, our investment in electric transmission would increase from approximately $1.1 billion at the end of 2006 to nearly $3.0 billion by the end of 2011.

In addition to its transmission projects, CL&P plans to make distribution capital expenditures intended to improve the reliability of its distribution system and to meet growth requirements on the distribution system. In 2006, CL&P's distribution capital expenditures totaled $210.3 million. In 2007, as a result of significant peak load growth in recent years, CL&P projects increasing distribution capital expenditures to approximately $270 million. CL&P plans to spend approximately $1.4 billion on distribution projects during the period 2007-2011.

In December, 2006, PSNH completed final testing and began commercial operation of its new wood-burning generation plant (Northern Wood Power Project), which replaced one of the three 50 MW boiler units at the coal-fired Schiller Station. As of December 31, 2006, PSNH had capitalized approximately $74 million related to this project.

In 2006, PSNH's transmission capital expenditures totaled $36 million and its distribution capital expenditures totaled $77.5 million. PSNH's generation capital expenditures totaled $32.1 million in 2006. In 2007, PSNH's transmission capital expenditures are projected to be approximately $83 million, its distribution capital expenditures are expected to be approximately $91 million and its generation capital expenditures approximately $37 million. The increase in distribution capital expenditures is due to additional reliability spending. The decline in generation capital expenditures is due to the completion in 2006 of the Northern Wood Power Project. During the period 2007-2011, PSNH plans to spend approximately $246 million on transmission projects and approximately $650 million on distribution and generation projects.

In 2006, WMECO's transmission capital expenditures totaled $13 million and its distribution capital expenditures totaled $30 million. In 2007, WMECO projects transmission capital expenditures to be approximately $16 million and its distribution capital expenditures to be approximately $34 million. During the period 2007-2011, WMECO plans on spending approximately $200 million on transmission projects and approximately $159 million on distribution projects.

In 2006, Yankee Gas' capital expenditures totaled $89.9 million, approximately 54% of which was for the construction of the LNG facility. The facility is expected to be put into service in mid-2007 in time for the 2007/ 2008 heating season at a cost of approximately $108 million. In 2006, Yankee Gas also spent $20.3 million on its reliability improvement program, $13.8 million on connecting new customers, and $6.9 million on other initiatives, including meters and information technology systems. In 2007, Yankee Gas projects total capital expenditures of approximately $62 million. The decline from 2006 is attributable to the expected completion of the LNG facility. During the period 2007-2011, Yankee Gas plans on making approximately $227 million of capital expenditures.

For more information regarding NU and its subsidiaries' construction and capital improvement program, see "Business Development and Capital Expenditures" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which is incorporated into this Form 10-K by reference.

STATUS OF EXIT FROM COMPETITIVE ENERGY BUSINESSES

Since we announced in March 2005 that we intended to exit from the wholesale energy marketing and energy services businesses of our subsidiary NU Enterprises, and our announcement in November 2005 that we would exit from the retail energy marketing and competitive generation businesses of NU Enterprises as well, we have made substantial progress towards our goal of exiting such businesses and focusing exclusively on our regulated business. An overview of this progress follows:

Competitive Generation. On November 1, 2006, we closed on the sale of NU Enterprises' 100% ownership in Northeast Generation Company (NGC), and of Holyoke Water Power Company's (HWP) 146 MW Mt. Tom coal-fired plant for an aggregate amount of $1.34 billion, which included the assumption of $320 million of NGC debt. We now own no competitive or merchant generation assets.

Wholesale Marketing Business: In 2005, Select Energy, Inc. (Select Energy) completed the divestiture of its New England wholesale sales contracts. Select Energy continues to serve its remaining PJM and New York wholesale sales contract obligations. As of December 31, 2006, the remaining sales obligations were approximately 7.5 million megawatt-hours (MWh), down from approximately 22 million MWh as of March of 2005 when we announced we were exiting the wholesale marketing business. Select Energy has also taken steps to reduce the volatility of these obligations by hedging a portion of them.

Retail Marketing Business: On June 1, 2006, Select Energy sold its retail marketing business, including its retail sales obligations and related supply contracts. Under the terms of the agreement, Select Energy paid the buyer approximately $11.5 million at closing and approximately $12.9 million in December of 2006, and will pay approximately $15 million by the end of 2007.

Energy Services Businesses: Woods Network, Inc. and the New Hampshire operations of Select Energy Contracting, Inc. (SECI), including Reeds Ferry, Inc., were sold in November of 2005. In January of 2006, the Massachusetts service division of SECI was sold. In April of 2006, NU Enterprises sold the services division of NGS Acquisition, Inc. (formerly Woods Electrical Co., Inc.), and in May of 2006, NU Enterprises sold its 100% ownership of Select Energy Services, Inc. (SESI).

Competitive Energy Business Assets Retained: Assets that have not yet either been sold or placed under contract to be sold by NU Enterprises are as follows:

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Select Energy's wholesale contracts (five PJM sales contracts, four of which expire in 2007 and one of which expires in 2008, one NYMPA sales contract that expires in 2013 and three power purchase contracts, two of which expire in 2007);

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Remaining assets, liabilities and contingencies associated with previously divested businesses or companies, including a contract to complete a cogeneration facility;

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Contracts associated with the wind-down of the remaining operations of Northeast Generation Services Company, SECI and NGS Acquisition, Inc., (formerly Woods Electrical Co., Inc.); and

-

E.S. Boulos Company.

In addition, provisions of the SESI purchase and sale agreement require NU to indemnify the buyer for estimated costs to complete or modify specific construction projects above specified levels. Provisions of the purchase and sale agreements related to the other divested businesses contain indemnifications and/or guarantees by NU. See Note 8H "Guarantees and Indemnifications," for further information regarding these guarantees and indemnifications.

For more information regarding the exit of the competitive businesses, see "NU Enterprises Exit" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's Annual Report to Shareholders, which is incorporated into this Form 10-K by reference.

FINANCING

NU paid common dividends totaling $112.7 million in 2006, compared to $87.6 million paid in 2005, reflecting an increase in the number of outstanding common shares of NU as a result of its share offering in December 2005, and increases in the quarterly dividend rate that were effective in the third quarters of 2005 and 2006.

Total debt of NU and its subsidiaries, including short-term debt, capitalized lease obligations and prior spent nuclear fuel liabilities, but not including rate reduction bonds or certificates, was approximately $3.0 billion as of December 31, 2006.

At December 31, 2006, NU maintained a parent company revolving credit facility of $500 million, and CL&P, PSNH, WMECO and Yankee Gas maintained a joint revolving credit facility of $400 million, both of which expire on November 6, 2010. At December 31, 2006, NU had no borrowings on that credit line, but approximately $67.5 million of letters of credit issued in connection with Select Energy's business were secured by that line. Neither CL&P, PSNH, WMECO nor Yankee Gas had any borrowings outstanding under their credit facility at December 31, 2006.

In addition, CL&P has access to funds under an arrangement with its subsidiary, CL&P Receivables Corporation (CRC). CRC has an agreement with CL&P to purchase up to $100 million of an undivided interest in CL&P's accounts receivables and unbilled revenues, which CRC sells to a highly rated financial institution on a limited recourse basis. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to the servicing of those receivables. At December 31, 2006, CL&P had no borrowings under this facility.

Financial Covenants in Credit Facilities

Under their revolving credit facility agreement, CL&P, WMECO, PSNH and Yankee Gas must each maintain a ratio of debt to total capitalization of no more than 65%. At December 31, 2006, CL&P, WMECO, PSNH, and Yankee Gas ratios were, and are expected to, remain in compliance with these ratios.

Under its revolving credit agreement, NU must maintain a ratio of debt to total capitalization of no more 67.5% through March 31, 2006 and 65.0% thereafter. At December 31, 2006, NU was, and expects to, remain in compliance with this ratio.

For more information regarding NU and its subsidiaries' financing, see "Notes to Consolidated Financial Statements" in NU's financial statements, the footnotes related to long-term debt, short-term debt, leases and the sale of accounts receivables, as applicable, in the notes to NU's, CL&P's, PSNH's, and WMECO's financial statements, and "Liquidity" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which are incorporated into this Form 10-K by reference.

STATUS OF NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and other New England electric utilities are the stockholders in three regional nuclear companies (the Yankee Companies). Each Yankee Company owns a single nuclear generating unit the Connecticut Yankee nuclear unit (CY), the Maine Yankee nuclear unit (MY), and the Yankee Rowe nuclear unit (YA). YA, CY and MY have been permanently removed from service and are being decontaminated and decommissioned. The stockholder-sponsors of each Yankee Company are responsible for proportional shares of the operating and decommissioning costs of each respective Yankee Company. CL&P's, PSNH's and WMECO's stock ownership percentages in the Yankee Companies are set forth below:

	CL&P	PSNH	WMECO	NU System
Connecticut Yankee Atomic Power Company (CYAPC)	34.5%	5.0%	9.5%	49.0%
Maine Yankee Atomic Power Company (MYAPC)	12.0%	5.0%	3.0%	20.0%
Yankee Atomic Electric Company (YAEC)	24.5%	7.0%	7.0%	38.5%

The Nuclear Regulatory Commission (NRC) has broad jurisdiction over the decommissioning activities at the Yankee Companies.

Decommissioning

CL&P, PSNH and WMECO each have significant decommissioning and plant closure cost obligations to CYAPC, YAEC and MYAPC. Each Yankee Company collects these costs through wholesale FERC-approved rates charged under power purchase agreements with CL&P, PSNH and WMECO. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates.

On June 10, 2004, the DPUC and the Connecticut Office of Consumer Counsel (OCC) filed a petition with the FERC seeking a declaratory order that CYAPC be allowed to recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but that such purchasers should not be allowed to recover in their retail rates any costs that the FERC might determine to have been imprudently incurred. The FERC rejected the DPUC's and OCC's petition, whereupon the DPUC filed an appeal of the FERC's decision with the D.C. Circuit Court of Appeals (Court of Appeals).

On November 16, 2006, FERC approved a settlement agreement between CYAPC, the DPUC, the OCC and Maine state regulators. The settlement agreement, which provides a revised decommissioning estimate of $642.9 million (in 2006 dollars), taking into account actual spending through 2005 and the current estimate for completing decommissioning and long-term storage of spent fuel, a gross domestic product escalator of 2.5% for costs incurred after 2006, and a 10% contingency factor for all decommissioning cost, disposes of the pending litigation at the FERC and the Court of Appeals, among other issues.

Spent Nuclear Fuel Litigation

YAEC, MYAPC, and CYAPC commenced litigation in 1998 against the United States Department of Energy (DOE) charging that the federal government breached contracts it entered into with each Yankee Company in 1983 under the Nuclear Waste Policy Act of 1982 to begin removing spent nuclear fuel from the respective nuclear plants no later than January 31, 1998 in return for payments by each Yankee Company into the Nuclear Waste Fund. The funds for those payments were collected from regional electric customers. The Yankee Companies initially claimed damages for incremental spent nuclear fuel storage, security, construction and other costs through 2010.

In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same period as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. The Yankee Companies believe they will have the opportunity in future lawsuits to seek recovery of actual damages incurred in the years following 2001-2002. The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE is established in the Yankee Companies' FERC-approved rate settlement agreement, although implementation will be subject to final determination of FERC. CL&P, PSNH and WMECO expect to pass any recovery onto its customers therefore no earnings are expected to result. The DOE appealed this decision in December 2006.

For more information regarding Nuclear matters, see "Notes to Consolidated Financial Statements" in NU's financial statements, the footnotes related to Spent Nuclear Fuel Disposal Costs, in the notes to NU's, CL&P's, PSNH's, and WMECO's financial statements and "Deferred Contractual Obligations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained within NU's and CL&P's Annual Reports to Shareholders, which is incorporated into this Form 10-K by reference.

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including the SEC, the FERC, the NRC and various state and/or local regulatory authorities with jurisdiction over the industry and the service areas in which each of our companies operates, including the DPUC having jurisdiction over CL&P and Yankee Gas, the NHPUC having jurisdiction over PSNH, and the DTE having jurisdiction over WMECO. Pursuant to the Energy Policy Act of 2005 (EPAct), PUHCA 1935, which provided the SEC with jurisdiction over various aspects of our operations, was repealed on February 8, 2006, and jurisdiction over a number of areas covered by PUHCA 1935 was assumed by the FERC under the PUHCA 2005 provisions of EPAct.

Environmental Regulation

We are subject to various federal, state and local requirements with respect to water quality, air quality, toxic substances, hazardous waste and other environmental matters. Additionally, our major generation and transmission facilities may not be constructed or significantly modified without a review of the environmental impact of the proposed construction or modification by the applicable federal or state agencies. Compliance with increasingly stringent environmental laws and regulations, particularly air and water pollution control requirements, may limit operations or require substantial investments in new equipment at existing facilities.

Water Quality Requirements

The federal Clean Water Act requires every "point source" discharger of pollutants into navigable waters to obtain a National Pollutant Discharge Elimination System (NPDES) permit from the United States Environmental Protection Agency or state environmental agency specifying the allowable quantity and characteristics of its effluent. States may also require additional permits for discharges into state waters. Our facilities are in the process of obtaining or renewing all required NPDES or state discharge permits in effect. Compliance with NPDES and state discharge permits has necessitated substantial expenditures and may require further significant expenditures, which are difficult to estimate, because of additional requirements or restrictions that could be imposed in the future, including requirements related to Sections 316(a) and 316(b) of the Clean Water Act for facilities owned by PSNH.

Air Quality Requirements

The Clean Air Act Amendments of 1990 (CAAA), as well as state laws in Connecticut, Massachusetts and New Hampshire, impose stringent requirements on emissions of sulfur dioxide (SO2) and nitrogen oxide (NOX) for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Installation of continuous emissions monitors and expanded permitting provisions also are included.

In New Hampshire, the Multiple Pollutant Reduction Program was signed into law in May 2002. Under this law, NOX, SO2 and Carbon Dioxide (CO2) emission are capped for current compliance beginning in 2007. A law was passed during the 2006 legislative session requiring reductions in emissions of mercury from PSNH's coal-fired plants. The law requires PSNH to install a wet flue gas desulphurization system, known as "scrubber" technology, to reduce mercury emissions (with the co-benefit of reductions in SO2 emissions as well) at Merrimack Station no later than July 1, 2013. PSNH currently anticipates the cost to comply with this law to be $250 million, but this amount has the potential to increase materially as the project is undertaken, primarily as a result of changes in commodity prices and labor costs.

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by nine northeastern states, including New Hampshire and Connecticut, to develop a regional program for stabilizing and reducing CO2 emissions from fossil-fired electric generators. This initiative proposes to stabilize CO2 emissions at current levels and require a ten percent reduction by 2020. The RGGI agreement (MOU) was signed on December 20, 2005 by the states of Connecticut, Delaware, Maine, New Jersey, New Hampshire, New York and Vermont. On January 18, 2007, Massachusetts also committed to the MOU. Each signatory state committed to propose for approval legislative and/or regulatory mechanisms to implement the program. RGGI may impact PSNH's Merrimack, Newington and Schiller stations. At this time, we cannot quantify the impact of the MOU on our companies. A model set of regulations was promulgated by the RGGI States in August 2006 to implement the program. Individual RGGI States are now initiating legislative and/or regulatory processes to implement their individual programs.

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws were implemented, we, like most industrial companies, disposed of residues from operations by depositing or burying such materials on-site or disposing of them at off-site landfills or facilities. Typical materials disposed of include coal gasification waste, fuel oils, ash, gasoline and other hazardous materials that might contain polychlorinated biphenyls. It has since been determined that deposited or buried wastes, under certain circumstances, could cause groundwater contamination or create other environmental risks. We have recorded a liability for what we believe is, based upon currently available information, our estimated environmental investigation and/or remediation costs for waste disposal sites for which we expect to bear legal liability, and continue to evaluate the environmental impact of our former disposal practices. Under federal and state law, government agencies and private parties can attempt to impose liability on us for such past disposal. At December 31, 2006, the liability recorded by us for our estimated environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $26.8 million, representing 51 sites. All cost estimates were made in accordance with generally accepted accounting principles where investigation and/or remediation costs are probable and reasonably estimable. These costs could be significantly higher if additional remedial actions become necessary.

The greatest liabilities currently relate to former manufactured gas plant (MGP) facilities which represent the largest share of future clean up costs. These facilities were owned and operated by predecessor companies to us from the mid-1800's to mid-1900's. By-products from the manufacture of gas using coal resulted in fuel oils, hydrocarbons, coal tar, purifier wastes, metals and other waste products that may pose risks to human health and the environment. We, through our subsidiaries, currently have partial or full ownership responsibilities at 28 former MGP sites. Of our total recorded liabilities of $26.8 million, a reserve of approximately $24.8 million has been established to address future investigation and/or remediation costs at MGP sites. In addition, remediation has been conducted at a coal tar contaminated river site in Massachusetts that is the responsibility of HWP. The cost to clean up that contamination may be more significant than currently estimated, but the level and extent of contamination is not yet known. Any and all exposure related to this site is not subject to ratepayer recovery. An increase to the environmental reserve for this site would be recorded in earnings for future periods and may be material.

In the past, we or our subsidiaries have received other claims from government agencies and third parties for the cost of remediating sites not currently owned by us but affected by our past disposal activities and may receive more such claims in the future. We expect that the costs of resolving claims for remediating sites about which we have been notified will not be material, but we cannot estimate the costs with respect to sites about which we have not been notified.

For further information on environmental liabilities, see Footnote 8B, "Commitments and Contingencies - Environmental Matters" contained within NU's 2006 Annual Report to Shareholders, which is incorporated into this Form 10-K by reference.

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from electric and magnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Although, weak health risk associations reported in some epidemiology studies remain unexplained, most researchers, as well as numerous scientific review panels, considering all significant EMF epidemiology and laboratory studies to date, agree that current information does not support the conclusion that EMF affects human health.

We have closely monitored research and government policy developments for many years and will continue to do so. In accordance with recommendations of various regulatory bodies and public health organizations, NU reduces EMF associated with new transmission lines by the use of designs that can be implemented without additional cost or at a modest cost. We do not believe that other capital expenditures are appropriate to minimize unsubstantiated risks.

FERC Hydroelectric Project Licensing

New Federal Power Act licenses may be issued for hydroelectric projects for terms of 30 to 50 years as determined by the FERC. Upon the expiration of an existing license, (i) the FERC may issue a new license to the existing licensee, or (ii) the United States may take over the project or the FERC may issue a new license to a new licensee, upon payment to the existing licensee of the lesser of the fair value or the net investment in the project, plus severance damages, less certain amounts earned by the licensee in excess of a reasonable rate of return.

PSNH owns nine hydroelectric generating stations with an aggregate of approximately 66.3 MW of capacity, with a current claimed capability representing winter rates, of approximately 69.5 MW. Of these nine plants, eight are licensed by the FERC under long-term licenses that expire on varying dates from 2009 through 2036 As a licensee under the FPA, PSNH and its licensed hydroelectric projects are subject to conditions set forth in the FPA and related FERC regulations, including provisions related to the condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment and severance damages and other matters.

FERC hydroelectric project licenses expire periodically and the generating facilities must be relicensed at such times. PSNH's Merrimack River Hydroelectric Project and Canaan Hydroelectric Project are currently in FERC relicensing proceedings. The FERC license for the Merrimack River Hydroelectric Project, which consists of the Amoskeag, Hooksett and Garvins Falls generating stations, expired on December 31, 2005. This project is currently operating under an annual FERC license, and the issuance of a new long-term license for the Merrimack River Hydroelectric Project is anticipated during the first half of 2007. The license for the Canaan Hydroelectric Project expires in 2009, and the issuance of a new license for the Canaan Hydroelectric Project is not anticipated for several years.

Licensed operating hydroelectric projects are not generally subject to decommissioning during the license term in the absence of a specific license provision which expressly permits the FERC to order decommissioning during the license term. However, the FERC has taken the position that under appropriate circumstances it may order decommissioning of hydroelectric projects at relicensing or may require the establishment of decommissioning trust funds as a condition of relicensing. The FERC may also require project decommissioning during a license term if a hydroelectric project is abandoned, the project license is surrendered or the license is revoked.

At this time, it appears unlikely that the FERC will order decommissioning of PSNH's hydroelectric projects at relicensing or that the projects will be abandoned, surrendered or the project licenses revoked. However, it is impossible to predict the outcome of the FERC relicensing proceedings with certainty, or to determine the impact of future regulatory actions on project economics. Until such time as a project is ordered to be decommissioned and the terms and conditions of a decommissioning order are known, any estimates of the cost of project decommissioning are preliminary and subject to change as new information becomes available.

EMPLOYEES

As of December 31, 2006, the NU system companies had 5,869 employees on their payrolls, excluding temporary employees, of which 1,812 were employed by CL&P, 1,286 by PSNH, 336 by WMECO, and 395 by Yankee Gas.

Approximately 2,200 employees of CL&P, PSNH, WMECO and Yankee Gas are covered by 11 union agreements. During 2005 and 2006, 11 contracts under negotiation have been ratified.

INTERNET INFORMATION

Our Web site address is http://www.nu.com. We make available through our Web site a link to the SEC's EDGAR site, at which site NU's, CL&P's, WMECO's and PSNH's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports may be reviewed. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at Northeast Utilities, 107 Selden Street, Berlin, Connecticut 06037.

Item 1A.

Risk Factors

We are subject to a variety of significant risks in addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" in Item 1, "Business," above. Our susceptibility to certain risks, including those discussed in detail below, could exacerbate other risks. These risk factors should be considered carefully in evaluating our risk profile.

The Infrastructure Of Our Transmission And Distribution System May Not Operate As Expected, And Could Require Additional Unplanned Expense Which Would Adversely Affect Our Earnings.

Our ability to manage operational risk with respect to our transmission and distribution systems is critical to the financial performance of our business. Our transmission and distribution businesses face several operational risks, including the breakdown or failure of or damage to equipment or processes (especially due to age), accidents and labor disputes. The failure of our transmission and distributions systems to operate as planned may result in increased capital investments, reduced earnings or unplanned increases in expenses, including higher maintenance costs.

Volatility in Electric and Gas Prices May Adversely Impact Sales

The nation's economy has been affected by the recent significant increases in energy prices, particularly fossil fuels. The impact of these increases has led to a decline in electricity and gas sales in our service territories and may result in further declines. Such declines without an adjustment in rates would reduce our revenues and limit future growth prospects.

Changes in Regulatory Policy May Adversely Affect Our Transmission Franchise Rights or Facilitate Competition for Construction of Large-Scale Transmission Projects, Which Could Adversely Affect Our

Earnings

Primarily through our subsidiary CL&P, we have undertaken a substantial transmission capital investment program and expect to invest approximately $2.5 billion in regulated electric transmission infrastructure from 2007 through 2011.

Although our public utility subsidiaries have exclusive franchise rights for transmission facilities in our service area, the demand for improved transmission reliability could result in changes in federal or state regulatory or legislative policy that could cause us to lose the exclusivity of our franchises or allow other companies to compete with us for transmission construction opportunities. Such a change in policy could result in reduced transmission capital investments, reduce earnings, and limit future growth prospects.

Changes in Regulatory or Legislative Policy Could Jeopardize Our Full Recovery of Costs Incurred By Our Distribution Companies

Under state law, our utility companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Each of these companies prepares and submits periodic rate filings with their respective state regulatory commissions for review and approval. There is no assurance that these state commissions will approve the recovery of all costs prudently incurred by the utility companies, such as for operation and maintenance, construction, as well as a return on investment on their respective regulated assets. Increases in these costs, coupled with increases in fuel and energy prices could lead to consumer or regulatory resistance to the timely recovery of such prudently incurred costs, thereby adversely affecting our business and results of operations.

In addition, CL&P and WMECO procure energy for a substantial portion of their customers via requests for proposal on an annual, semi-annual or quarterly basis. CL&P and WMECO receive approvals of recovery of these contract prices from the DPUC and DTE, respectively. While both regulators have consistently approved solicitation processes, results and recovery of costs, management cannot predict the outcome of future solicitation efforts or the regulatory proceedings related thereto.

The energy requirements for PSNH are currently met primarily through PSNH's generation resources or fixed-price forward purchase contracts. The remaining energy needs are met through spot market or bilateral energy purchases. Unplanned forced outages of its generating plants could increase the level of energy purchases needed by PSNH and therefore increase the market risk associated with procuring the necessary amount of energy to meet requirements. PSNH recovers these costs through its SCRC, subject to a prudence review by the NHPUC. Management cannot predict the outcome of future regulatory proceedings related to recovery of these costs.

Changes In Regulatory And/Or Legislative Policy Could Negatively Impact Regional Transmission Cost Allocation Rules.

The existing New England Transmission tariff allocates the costs of transmission investment that provide regional benefits to all customers in New England. As new investment in regional transmission infrastructure occurs in any one state, there is a sharing of these regional costs across all of New England. This regional cost allocation is contractually agreed to remain in place until 2010 by the Transmission Operations Agreement signed by all of the New England transmission owning utilities but can be changed with the approval of a majority of the transmission owning utilities thereafter. Post 2010, certain changes to the terms of the Transmission Operations Agreement could have adverse effects on our distribution companies' local rates. Management is working to retain the existing regional cost allocation treatment but cannot predict the actions of the states or utilities in the region.

The Loss of Key Personnel or the Inability to Hire and Retain Qualified Employees Could Have an Adverse Effect on our Business, Financial Condition and Results of Operations.

Our operations depend on the continued efforts of our employees. Retaining key employees and maintaining the ability to attract new employees are important to both our operational and financial performance. We cannot guarantee that any member of our management or any key employee at the NU or subsidiary level will continue to serve in any capacity for any particular period of time. In addition, a significant portion of our workforce, including many workers with specialized skills maintaining and servicing the electrical infrastructure, will be eligible to retire over the next five to ten years. Such highly skilled individuals cannot be quickly replaced due to the technically complex work they perform. We are developing strategic workforce plans to identify key functions and proactively implement plans to assure a ready and qualified workforce.

Grid Disturbances, Severe Weather, or Acts of War or Terrorism Could Negatively Impact our Business.

Because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business continuity due to a disruption or black-out caused by an event (severe storm, generator or transmission facility outage, or terrorist action) on an interconnected system or the actions of another utility. In addition, we are subject to the risk that acts of war or terrorism could negatively impact the operation of our system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results of operations.

Severe weather, such as ice and snow storms, hurricanes and other natural disasters, may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The cost of repairing damage to our operating subsidiaries' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial. The effect of the failure of our facilities to operate as planned would be particularly burdensome during a peak demand period, such as during the hot summer months.

Changes in Regulatory or Legislative Policy May Delay Completion of Our Transmission Projects or Adversely Affect Our Ability to Recover Our Investments or Result in Lower than Expected Rates of Return

The successful implementation of our transmission construction plans is subject to the risk that new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could impact our ability to meet our construction schedule and/or require us to incur additional expenses, and may adversely affect our ability to achieve forecast levels of revenues.

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

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

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

A Negative Change In NU's Credit Ratings Could Require NU To Post Cash Collateral And Affect our Ability To Obtain Financing

NU's senior unsecured debt ratings by Moody's Investors Service, Standard & Poor's, Inc. and Fitch Ratings are currently Baa2, BBB- and BBB, respectively, with stable outlooks. Were any of these ratings to decline to non-investment grade level, Select Energy could be asked to provide, as of December 31, 2006, approximately $136.8 million of collateral or letters of credit to unaffiliated counterparties and $52.4 million to several independent system operators and unaffiliated local distribution companies (LDCs) under agreements largely guaranteed by NU. While NU's credit facilities are in amounts that would be adequate to meet calls at that level, our ability to meet any future calls would depend on our liquidity and access to bank lines and the capital markets at such time.

We expect to obtain the liquidity needed for our capital programs through bank borrowings and the issuance of long-term debt at the subsidiary level. While we are reasonably confident these funds will be available on a timely basis and on reasonable terms, failure to obtain such financing could constrain our ability to finance regulated capital projects. In addition, any ratings downgrade of our securities or those of our subsidiaries could negatively impact the cost or availability of capital.

Changes in Forecasted Wholesale Electric Sales Could Require Select Energy to Acquire or Sell Additional Electricity on Unfavorable Terms

Select Energy's remaining wholesale sales contracts are to provide electricity to requirements customers, who are primarily regulated LDCs and municipal electric companies. Under the terms of its remaining requirements contracts, Select Energy is required to provide a portion of the customer's electricity requirements at all times. The volumes sold under these contracts vary based on the usage of the underlying retail electric customers, and usage is dependent upon factors outside of Select Energy's control, such as unanticipated migration or inflow of customers, and weather. As a result, the varying sales volumes could be different than the supply volumes that Select Energy expected to utilize from electricity purchase contracts acquired to serve the requirements contracts. Differences between actual sales volumes and supply volumes could require Select Energy to purchase additional electricity or sell excess electricity, both of which are subject to market conditions which change due to weather, plant availability, transmission congestion, and input fuel costs. The purchase of additional electricity at high prices or sale of excess electricity at low prices can impact Select Energy's cost to serve its remaining wholesale sales customers.

We Are Subject To Litigation Which Could Result In Large Cash Judgments against us

We are engaged in litigation that could result in the imposition of large cash judgments against us. This litigation includes a civil lawsuit between Consolidated Edison, Inc. (Con Edison) and NU relating to the parties' October 13, 1999 Agreement and Plan of Merger.

We may also be subject to future litigation based on asserted or unasserted claims and cannot predict the outcome of any of these proceedings. Adverse outcomes in existing or future litigation could result in the imposition of substantial cash damage awards against us.

Further information regarding these legal proceedings, as well as other matters, is set forth in Item 3, "Legal Proceedings."

Costs of Compliance with Environmental Regulations May Increase and Have an Adverse Effect on our Business and Results of Operations

Our subsidiaries' operations are subject to extensive federal, state and local environmental statutes, rules and regulations which regulate, among other things, air emissions, water discharges and the management of hazardous and solid waste. In particular, more stringent regulations of carbon dioxide and mercury emissions have been proposed in various New England states. Compliance with these requirements requires us to incur significant costs relating to environmental monitoring, installation of pollution control equipment, emission fees, maintenance and upgrading of facilities, remediation and permitting. The costs of compliance with these legal requirements may increase in the future. An increase in such costs, unless promptly recovered, could have an adverse impact on our business and results of operations, financial position and cash flows. For further information, see Item 1, "Business - Other Regulatory and Environmental Matters - Environmental Regulation."

Any failure by us to comply with environmental laws and regulations, even if due to factors beyond our control, or reinterpretations of existing requirements, could also increase costs. Existing environmental laws and regulations may be revised or new laws and regulations seeking to protect the environment may be adopted or become applicable to us. Revised or additional laws could result in significant additional expense and operating restrictions on our facilities or increased compliance costs which may not be fully recoverable in distribution company rates for regulated generation. The cost impact of any such legislation would be dependent upon the specific requirements adopted and cannot be determined at this time.

Item 1B. Unresolved Staff Comments

NU does not have any unresolved SEC staff comments.

Item 2. Properties

Transmission and Distribution System

At December 31, 2006, the electric operating subsidiaries of NU owned 196 transmission and 271 distribution substations that had an aggregate transformer capacity of 27,445,016 kilovoltamperes (kVa) and 2,255,770 kVa, respectively; 3,091 circuit miles of overhead transmission lines ranging from 69 kilovolt (KV) to 345 KV, and 242 cable miles of underground transmission lines ranging from 69 KV to 345 KV; 34,637 pole miles of overhead and 2,726 conduit bank miles of underground distribution lines; and 464,898 line transformers in service with an aggregate capacity of 21,202,617 kVa.

Electric Generating Plants

As of December 31, 2006, PSNH owned the following electric generating plants:

Name of Plant (Location)	Type	Year Installed	Claimed Capability* (kilowatts)
Total - Fossil-Steam Plants	(7 units)	1952-78	999,554
Total - Hydro-Conventional	(20 units)	1917-83	69,510
Total - Internal Combustion	(5 units)	1968-70	101,461
Total PSNH Generating Plant	(32 units)		1,170,525

*Claimed capability represents winter ratings as of December 31, 2006. The nameplate capacity of the generating plants is approximately 1,200 MW.

Neither CL&P nor WMECO owned any electric generating plants during 2006.

Franchises

CL&P - Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, CL&P has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to provide electric transmission and distribution services in the respective areas in which it is now supplying such service.

In addition to the right to provide electric transmission and distribution services as set forth above, the franchises of CL&P include, among others, limited rights and powers, as set forth in Title 16 of the Connecticut General Statutes and the special acts of the General Assembly constituting its charter, to manufacture, generate, purchase and/or sell electricity at retail, including to provide standard service, supplier of last resort service and backup service, to sell electricity at wholesale and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of CL&P include the power of eminent domain. Title 16 of the Connecticut General Statutes was amended by Public Act 03-135, "An Act Concerning Revisions to the Electric Restructuring Legislation," to prohibit an electric distribution company from owning or operating generation assets. However, Public Act 05-01, "An Act Concerning Energy Independence," allows CL&P to own up to 200 MW of peaking facilities if the DPUC determines that such facilities will be more cost effective than other options for mitigating FMCCs and LICAP costs. CL&P has divested all of its generation assets and is now acting as a transmission and distribution company.

PSNH - The NHPUC, pursuant to statutory requirement, has issued orders granting PSNH exclusive franchises to distribute electricity in the respective areas in which it is now supplying such service.

In addition to the right to distribute electricity as set forth above, the franchises of PSNH include, among others, rights and powers to manufacture, generate, purchase, and transmit electricity, to sell electricity at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on certain public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of PSNH include the power of eminent domain.

WMECO - WMECO is authorized by its charter to conduct its electric business in the territories served by it, and has locations in the public highways for transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only, and for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. In addition, WMECO has been granted easements for its lines in the Massachusetts Turnpike by the Massachusetts Turnpike Authority and pursuant to state laws, has the power of eminent domain.

The Massachusetts restructuring legislation defines service territories as those territories actually served on July 1, 1997 and following municipal boundaries to the extent possible. The restructuring legislation further provides that until terminated by law or otherwise, distribution companies shall have the exclusive obligation to serve all retail customers within their service territories and no other person shall provide distribution service within such service territories without the written consent of such distribution companies. Pursuant to the Massachusetts restructuring legislation, the DTE was required to define service territories for each distribution company, including WMECO. The DTE subsequently determined that there were advantages to the exclusivity of service territories and issued a report to the Massachusetts Legislature recommending against, in this regard, any changes to the restructuring legislation.

HWP and Holyoke Power and Electric Company (HP&E) - HWP, and its wholly owned subsidiary HP&E, are authorized by their charters to conduct their businesses in the territories served by them. HWP's electric business is subject to the restriction that sales be made by written contract in amounts of not less than 100 horsepower to purchasers who use the electricity in their own business in the counties of Hampden or Hampshire, Massachusetts and cities and towns in these counties, and customers who occupy property in which HWP has a financial interest, by ownership or purchase money mortgage. In connection with the sale of certain of HWP's and HP&E's assets to the city of Holyoke Gas and Electric Department (HG&E) effective December 2001, HWP agreed not to distribute electricity at retail in Holyoke and surrounding towns unless other sellers can legally compete with HG&E and to amend the charters of HWP & HP&E to reflect that limitation.

The two companies have locations in the public highways for their transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and, for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. HP&E has no retail service territory area and sells electric power exclusively at wholesale.

Yankee Gas - Yankee Gas directly and from its predecessors in interest holds valid franchises to sell gas in the areas in which Yankee Gas supplies gas service. Generally, Yankee Gas holds franchises to serve customers in areas designated by those franchises as well as in most other areas throughout Connecticut so long as those areas are not occupied and served by another gas utility under a valid franchise of its own or are not subject to an exclusive franchise of another gas utility. Yankee Gas' franchises are perpetual but remain subject to the power of alteration, amendment or repeal by the General Assembly of the State of Connecticut, the power of revocation by the DPUC and certain approvals, permits and consents of public authorities and others prescribed by statute. Generally, Yankee Gas' franchises include, among other rights and powers, the right and power to manufacture, generate, purchase, transmit and distribute gas and to erect and maintain certain facilities on public highways and grounds; and the right of eminent domain, all subject to such consents and approvals of public authorities and others as may be required by law.

Item 3. Legal Proceedings

1.

Consolidated Edison, Inc. v. NU - Merger Litigation

On March 5, 2001, Con Edison advised NU that it was unwilling to close its merger with NU on the terms set forth in the parties' 1999 merger agreement (the Merger Agreement). On March 12, 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

On May 11, 2001, Con Edison filed an amended complaint seeking damages for breach of contract, fraudulent inducement and negligent misrepresentation.

On October 12, 2005, the United State Court of Appeals for the Second Circuit issued a decision concluding that NU shareholders had no right to sue Con Edison for its alleged breach of the Merger Agreement. As a result, the Second Circuit did not reach the second issue presented for review which was whether the right to pursue recovery of the $1 billion merger premium belongs to NU shareholders who held shares at the time of the breach or those who hold shares if and when a judgment is rendered against Con Edison. NU filed for rehearing and suggested an en banc review on October 26, 2005. By order dated January 3, 2006, NU's request for rehearing was denied. The ruling leaves intact the remaining claims between NU and Con Edison for breach of contract, which include NU's claim for recovery of costs and expenses of approximately $32 million, and Con Edison's claim for "at least $314 million" in damages. NU opted not to seek review of this ruling by the United States Supreme Court.

On April 7, 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. NU's motion asserts that NU is entitled to judgment in its favor with respect to this claim based on the undisputed material facts and applicable law. The matter is fully briefed and awaiting a decision.

It is not possible to predict either the outcome of this matter or its ultimate effect on NU.

2.

Constellation Power Source, Inc. (Constellation) v. Select Energy, Inc.

This case involves a dispute between Select Energy and Constellation over responsibility for socialized congestion charges imposed by ISO-NE prior to the implementation of Standard Market Design (SMD) on March 1, 2003, and responsibility for congestion charges and losses following implementation of SMD. Constellation filed a complaint in the U.S. District Court for the District of Connecticut against Select Energy claiming that Select Energy was responsible for pre- and post-SMD congestion and losses amounting to approximately $9.7 million. Select Energy filed a counterclaim seeking to recover the $2.5 million in pre-SMD charges that Constellation had refused to pay.

The case was tried to the Court in August 2006. On November 14, 2006, the court issued its Memorandum of Decision and found in favor of Select Energy, with respect to its counterclaim for recovery of pre-SMD congestion and losses. The court also awarded Constellation its "pro rata share of the LMP Differential that Select Energy received from CL&P in connection with the settlement of the FERC proceeding, plus prejudgment interest as provided in the parties' agreement." Pursuant to an order of the Court, the parties made their respective damages filings with the Court on December 13, 2006. On January 23, 2007, the Court issued its final decision and order addressing the issue of damages. The net effect of the Court's ruling is that Select Energy will have to pay Constellation approximately $1.7 million as of the date entered, with interest accruing at a net rate of approximately $500 per day until the judgment is paid. The parties have reached a settlement pursuant to which Select Energy agreed to pay Constellation $2 million, thereby ending the litigation.

3.

NRG Bankruptcy

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

A. Station Service

NRG has disputed its responsibility to pay for the provision of station service by CL&P to NRG's Connecticut generating plants (approximately $26 million, including late charges). The FERC issued a decision on December 20, 2002 that NRG had agreed that station service from CL&P would be subject to CL&P's applicable retail rates, and that states (i.e., the DPUC) have jurisdiction over the delivery of power to end users even where power is not delivered via distribution facilities. NRG refused CL&P's subsequent demand for payment, and on April 3, 2003, CL&P petitioned the DPUC for a declaratory order enforcing the FERC's December 20, 2002 decision. Prior to the issuance of a decision by the DPUC, NRG filed a petition under Chapter 11 of the U.S. Bankruptcy Code, staying any further action by the DPUC.

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

B. Yankee Gas

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

C. Congestion Charges

On August 5, 2002, CL&P withheld the past due congestion charges from its payment to NRG pursuant to contractual provisions allowing the withholding of disputed sums. CL&P continued to withhold congestion charges from its monthly payments to NRG, through March 1, 2003, and at present is withholding approximately $28 million. On November 28, 2001, CL&P filed a complaint against NRG in Connecticut Superior Court alleging breach of contract arising from the failure of NRG to pay approximately $29.6 million of socialized congestion charges. The case was removed to U.S. District Court for the District of Connecticut. NRG filed a counterclaim seeking recovery of all amounts CL&P has withheld. Discovery is complete and CL&P's motion for summary judgment is pending. No trial date is currently scheduled.

4.

CYAPC/FERC Proceeding

On July 1, 2004, CYAPC filed with the FERC to increase its decommissioning collections from $16.7 million per year (in 2000 dollars) to $93 million per year (in 2003 dollars) for the six-year period beginning January 1, 2005. The 2003 estimate projects an increase of $395.6 million in 2003 dollars and a total cost to complete decommissioning of $831.3 million in 2003 dollars.

On August 30, 2004, the FERC issued an order accepting the CYAPC rate filing, suspending collections for five months and establishing hearing procedures.

The FERC administrative law judge conducted hearings on the reasonableness of the decommissioning rates in the spring of 2005. The DPUC argued that CYAPC's actions were imprudent and recommended a disallowance in the range of approximately $225 to $234 million. The FERC trial staff argued that CYAPC should have used a lower gross domestic product (GDP) escalation rate in calculating the level of decommissioning charges and that use of such rate would reduce charges by $36 million. In post trial briefs, the FERC trial staff also claimed that CYAPC's actions were imprudent and increases in decommissioning charges should be disallowed.

In an initial decision rendered on November 22, 2005, the FERC trial judge found no imprudence on CYAPC's part, and thus there was no basis for a rate disallowance. However, the trial judge agreed with the FERC trial staff's lower GDP escalator for calculating the decommissioning rate increase.

On November 16, 2006, FERC approved a settlement among CYAPC, the DPUC, the OCC, the Maine Public Utilities Commission and the Maine Public Advocate that disposes of the pending decommissioning litigation at FERC and at the D.C. Circuit. The settlement also resolves the dispute over the incentive mechanism contained in the 2000 settlement between the parties, the disposition of the net proceeds from CY's settlement with Bechtel, CY's recovery of the costs of completing decommissioning, and CY's payment of dividends and return of equity capital to its shareholders.

Under the terms of the settlement, the parties have agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars), taking into account actual spending through 2005 and the current estimate for completing decommissioning and long-term storage of spent fuel, a GDP escalator of 2.5% for costs incurred post 2006, and a 10% contingency factor for all decommissioning costs.

NU's electric operating subsidiaries collectively own 49.0 % of CYAPC, as follows: CL&P - 34.5 %, PSNH - 5.0 %and WMECO - 9.5%.

5.

YAEC   Decommissioning

On November 23, 2005, YAEC filed a request with FERC to revise the level of its decommissioning collections, based on an increased cost estimate. A 2003 settlement had provided for annual charges of $55.6 million through 2005 and $14 million from 2006 through 2010, with certain adjustments. YAEC's proposal is to increase 2006 collections to $54.9 million and increase 2007 through 2010 collections to $23.5 million. YAEC has asked FERC for an effective date of February 1, 2006. On January 31, 2006, FERC accepted the rate increase with a February 1, 2006 effective date, subject to refund, and set the case for settlement proceedings.

On May 1, 2006, YAEC filed with FERC a proposed settlement with the Connecticut DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service. The settlement reduces decommissioning charges to YAEC's wholesale utility customers by, among other items, revising the decommissioning estimate, including contingency and projected escalation, extending the collection period for charges through December 2014, reduces certain expenses, reconciling certain decontamination and dismantlement expenses, and adjusting charges based on the decommissioning trust fund's actual investment earnings. The settlement proposes a new estimate of decommissioning charges of $212.6 million, reflecting a $28.2 million reduction compared to the 2005 decommissioning cost of estimate.

The settlement became effective upon FERC's approval in December, 2006, but did not affect the level of 2006 charges. Charges from 2007 through 2014 will drop to approximately $11.7 million per year, subject to certain adjustments.

NU's electric operating subsidiaries collectively own 38.5 % of YAEC, as follows: CL&P - 24.5%, PSNH - 7.0 % and WMECO   7.0%.

6.

Yankee Companies v. U.S. Department of Energy

A. Spent Nuclear Fuel Litigation

YAEC, MYAPC, and CYAPC commenced litigation in 1998 against the DOE charging that the federal government breached contracts it entered into with each company in 1983 under the Nuclear Waste Policy Act of 1982 to begin removing spent nuclear fuel from the respective nuclear plants no later than January 31, 1998 in return for payments by each company into the Nuclear Waste Fund. The funds for those payments were collected from regional electric customers. The Yankee Companies initially claimed damages for incremental spent nuclear fuel storage, security, construction and other costs through 2010.

In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same period as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE is established in the Yankee Companies' FERC-approved rate settlement agreement, although implementation will be subject to final determination of FERC. CL&P, PSNH and WMECO expect to pass any recovery onto its customers therefore no earnings are expected to result.

The Court of Federal Claims, following precedent set in another case, did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. The Yankee Companies believe they will have the opportunity in future lawsuits to seek recovery of actual damages incurred in the years following 2001/2002. The DOE appealed the decision and the Yankee Companies filed cross-appeals. The application of any damages which are ultimately recovered to benefit customers is established in the Yankee Companies' FERC-approved rate settlement agreements, although implementation will be subject to the final determination of the FERC.

B. Uranium Enrichment Litigation

In 2001, Northeast Utilities Service Company (NUSCO) asserted claims against the DOE in the Court of Federal Claims for overcharges for purchases of uranium enrichment separative work units (SWUs) for CYAPC's nuclear unit and the nuclear units located at Millstone Power Station in Waterford, Connecticut between 1986 and 1993 (D&D Claims). The NUSCO case was stayed by the Court of Federal Claims while other D&D Claims cases were being litigated. Beginning in 2005, NUSCO joined a number of other utilities in a consortium in an attempt to negotiate a settlement agreement with the DOE. In late-2006, a settlement was reached between the consortium and the DOE. The distribution of proceeds under the settlement agreement totals approximately $0.8 million for CYAPC and approximately $1.4 million related to the Millstone units. This distribution is based on the total number of SWUs purchased for CYAPC's unit and the Millstone units during the applicable period covered by the litigation. We believe it is likely that the net proceeds from the settlement will be credited to ratepayers. CL&P, PSNH and WMECO collectively own 49% of CYAPC. Prior to March 31, 2001, CL&P, PSNH and WMECO collectively owned 100% of Millstone 1 and 2 and 68.02 % of Millstone 3.

7.

Enron Bankruptcy Claim

CL&P filed a proof of claim in the sum of $42.9 million against Enron Power Marketing, Inc. (EPMI) in the U. S. Bankruptcy Court for the Southern District of New York. The claim is for damages resulting from the rejection of the December 22, 2000 electricity purchase agreement between EPMI and CL&P, which was related to an agreement the Connecticut Resource Recovery Authority had entered into with Enron. EPMI, through the Enron bankruptcy estate, objected to the CL&P claim, CL&P filed a response, and litigation ensued in the bankruptcy court. CL&P and Enron have now agreed to settle the matter by agreeing that the CL&P's claim will have a face value of $19.75 million. CL&P cannot estimate what percentage of the claim will be paid once the agreement is approved, but the proceeds from the liquidation of the claim will be credited to ratepayers. The settlement requires DPUC and bankruptcy court approval and the parties anticipate that a motion to approve the settlement will be filed in the second quarter of 2007.

8.

Connecticut MGP Cost Recovery

On August 5, 2004, Yankee Gas and CL&P (NU Companies) demanded contribution from UGI Utilities, Inc. (UGI) of Pennsylvania for past and future remediation costs related to historic MGP operations on thirteen sites currently or formerly owned by the NU Companies (Yankee Gas is responsible for ten of the sites, CL&P for two of the sites, and both companies share responsibility for one site) in a number of different locations throughout the State of Connecticut. The NU Companies alleged that UGI controlled operations of the plants at various times throughout the period 1883 to 1941, when UGI was forced to divest its interests. Investigations and remediation costs at the sites to date total over $20 million against reserves, and projected potential remediation costs for all sites--based on litigation modeling assumptions--could total as much as $228 million. At this point, the costs are not estimable and probable from an accounting standpoint.

In September 2006, the NU Companies filed a complaint against UGI in the U.S. District Court for the District of Connecticut seeking a fair and equitable contribution for the actual and anticipated remediation costs related to the former MGP operations. On November 6, UGI answered the complaint, denying the material allegations asserted against it. The case is now in the discovery phase.

9.

Dominion Nuclear-Station Service

On July 24, 2006, Dominion Nuclear Connecticut, Inc. (DNCI) filed a complaint at FERC, claiming that, because as of December 1, 2005, DNCI sought to "self-supply" its station service power through the ISO-NE settlement system rather than from CL&P as a Transitional Standard Service retail customer, it is not required to buy retail delivery service for that power. On August 14, 2006, CL&P answered the complaint, supported by the Connecticut DPUC, OCC and the AG.

On September 22, 2006, FERC issued an order finding that CL&P is not authorized to impose local distribution charges for station power delivery service on DNCI, and directed CL&P to cease charging DNCI retroactive to December 1, 2005. Since that date, DNCI has withheld approximately $1.7 million (including interest). CL&P sought rehearing and clarification on October 23, 2006. (See "NRG Bankruptcy - Station Service" under entry 3 of this Item 3 for a contrasting view taken by the DPUC).

10.

Other Legal Proceedings

The following sections of Item 1, "Business" discuss additional legal proceedings: See "Regulated Electric Distribution," "Regulated Electric Transmission," and "Regulated Gas Operations" for information about various state restructuring and rate proceedings, civil lawsuits related thereto, and information about proceedings relating to power, transmission and pricing issues; "Status of Nuclear Decommissioning" for information related to high-level nuclear waste; and "Other Regulatory and Environmental Matters" for information about proceedings involving surface water and air quality requirements, toxic substances and hazardous waste, EMF, licensing of hydroelectric projects, and other matters. In addition, see Item 1A, "Risk Factors" for general information about several significant risks.

EXECUTIVE OFFICERS OF NU

Name

Age

Business Experience During Past 5 Years

Gregory B. Butler

49

Senior Vice President and General Counsel of NU since December 1, 2005 and of CL&P, PSNH and WMECO since March 9, 2006, and a Director of Northeast Utilities Foundation, Inc. since December 1, 2002; previously Senior Vice President, Secretary and General Counsel of NU from August 31, 2003 to December 1, 2005; Vice President, Secretary and General Counsel of NU from May 1, 2001 through August 30, 2003.

Lawrence E. De Simone

59

Retired as of January 1, 2007; previously served as President-Competitive Group of NU and President of NU Enterprises, Inc., from October 25, 2004 to December 31, 2006 and Chairman, President and Chief Executive Officer of Select Energy, Inc. from February 1, 2005 to December 31, 2006; previously Executive Vice President - Regulated Business and Services of PPL Corporation from January 1, 2004 to August 31, 2004; Executive Vice President - Supply of PPL Corporation from October 2001 to December 31, 2003.

Cheryl W. Grisé (*)

54

Executive Vice President of NU since December 1, 2005; Chief Executive Officer of CL&P, PSNH and WMECO from September 10, 2002 to January 15, 2007, a Director of CL&P from May 1, 2001 to January 15, 2007, PSNH from May 14, 2001 to January 15, 2007 and WMECO from June 2001 to January 15, 2007, and a Director of Northeast Utilities Foundation, Inc. since September 23, 1998; previously President - Utility Group of NU from May 2001 to December 1, 2005.

David R. McHale

46

Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO since January 1, 2005 and a Director of PSNH and WMECO since January 1, 2005 and CL&P since January 15, 2007; previously Vice President and Treasurer of NU, WMECO and PSNH from July 1998 to December 31, 2004.

Leon J. Olivier

58

Executive Vice President - Operations of NU since February 13, 2007; Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007; Director of PSNH and WMECO since January 17, 2005 and a Director of CL&P since September 2001. Previously Executive Vice President of NU from December 1, 2005 to February 13, 2007; President - Transmission Group of NU from January 17, 2005 to December 1, 2005; President and Chief Operating Officer of CL&P from September 2001 to January 2005.

Shirley M. Payne

55

Vice President - Accounting and Controller of NU since February 13, 2007, and CL&P, PSNH and WMECO since January 29, 2007. Previously Vice President, Corporate Accounting and Tax of TECO Energy, Inc. from July 2000 to January 26, 2007 and Tax Officer of Tampa Electric Company from April 1999 to January 26, 2007.

Charles W. Shivery

61

Chairman of the Board, President and Chief Executive Officer of NU since March 29, 2004; Chairman and a Director of CL&P, PSNH and WMECO since January 19, 2007. Previously, President (interim) of NU from January 1, 2004 to March 29, 2004 and a Director of Northeast Utilities Foundation since March 3, 2004; previously President - Competitive Group of NU and President and Chief Executive Officer of NU Enterprises, Inc., from June 2002 through December 2003.

(*)

Mrs. Grisé is a Director of MetLife, Inc. and Dana Corporation.

Item 4. Submission Of Matters To a Vote of Security Holders

No event that would be described in response to this item occurred with respect to NU or CL&P.

The information called by Item 4 is omitted for PSNH and WMECO pursuant to Instruction I (2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries.)

Part II

Item 5. Market for The Registrants' Common Equity and Related Stockholder Matters

NU. The common shares of NU are listed on the New York Stock Exchange. The ticker symbol is "NU," although it is frequently presented as "Noeast Util" and/or "NE Util" in various financial publications. The high and low closing sales prices for the past two years, by quarters, are shown below.

Year	Quarter	High	Low
2006	First	$ 20.21	$ 19.25
	Second	20.97	19.24
	Third	23.57	20.84
	Fourth	28.81	23.38
2005	First	$ 19.45	$ 17.84
	Second	21.22	18.11
	Third	21.79	19.47
	Fourth	20.08	17.61

There were no purchases made by or on behalf of NU or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of common stock during the fourth quarter of the year ended December 31, 2006. Information with respect to the performance of NU's common shares is contained in the "Share Performance Chart" from the Proxy Statement to be dated March 20, 2007, which information is incorporated herein by reference.

As of January 31, 2007, there were 50,849 common shareholders of NU on record. As of the same date, there were a total of 175,453,290 common shares issued, including 1,483,561 unallocated Employee Stock Ownership Plan (ESOP) shares held in the ESOP trust.

On February 13, 2007, the NU Board of Trustees approved the payment of 18.75 cent per share dividend, payable on March 31, 2007, to shareholders of record as of March 1, 2007.

On November 13, 2006, the NU Board of Trustees approved the payment of 18.75 cent per share dividend, payable on December 30, 2006, to shareholders of record as of December 1, 2006.

On May 9, 2006, the NU Board of Trustees approved the payment of 18.75 cent per share dividend, payable on September 29, 2006 to shareholders of record as of September 1, 2006.

On April 11, 2006, the NU Board of Trustees approved the payment of 17.5 cent per share dividend, payable on June 30, 2006 to shareholders of record on June 1, 2006.

On February 14, 2006, the NU Board of Trustees approved the payment of 17.5 cent per share dividend, payable on March 31, 2006 to shareholders of record as of March 1, 2006.

On October 11, 2005, the NU Board of Trustees approved the payment of 17.5 cent per share dividend, payable on December 30, 2005 to shareholders of record as of December 1, 2005.

On May 10, 2005, the NU Board of Trustees approved the payment of 17.5 cent per share dividend, payable on September 30, 2005 to shareholders of record as of September 1, 2005.

On April 12, 2005, the NU Board of Trustees approved the payment of 16.25 cent per share dividend, payable on June 30, 2005 to shareholders of record as of June 1, 2005.

On January 31, 2005, the NU Board of Trustees approved the payment of 16.25 cent per share dividend, payable on March 31, 2005 to shareholders of record as of March 1, 2005.

Information with respect to dividend restrictions for NU, CL&P, PSNH, and WMECO is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity" and in the "Notes to Consolidated Financial Statements," within each company's 2006 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P, PSNH and WMECO. There is no established public trading market for the common stock of CL&P, PSNH and WMECO. The common stock of CL&P, PSNH and WMECO is held solely by NU.

During 2006 and 2005, CL&P approved and paid $63.7 million and $53.8 million, respectively, of common stock dividends to NU.

During 2006 and 2005, PSNH approved and paid $41.7 million and $42.4 million, respectively, of common stock dividends to NU.

During 2006 and 2005, WMECO approved and paid $7.9 million and $7.7 million, respectively, of common stock dividends to NU.

For information regarding securities authorized for issuance under equity compensation plans, see Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters," included in this report on Form 10-K.

Item 6. Selected Financial Data

NU. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within NU's 2006 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within CL&P's 2006 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within PSNH's 2006 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within WMECO's 2006 Annual Report, which information is incorporated herein by reference.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

NU. Reference is made to information under the heading "Management's Discussion and Analysis and Results of Operations" contained within NU's 2006 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Management's Discussion and Analysis and Results of Operations" contained within CL&P's 2006 Annual Report, which information is incorporated herein by reference.

PSNH. With respect to PSNH's results of operations, reference is made to information under the heading "Results of Operations" contained within PSNH's 2006 Annual Report, which information is incorporated herein by reference.

WMECO. With respect to WMECO's results of operations, reference is made to information under the heading "Results of Operations" contained within WMECO's 2006 Annual Report, which information is incorporated herein by reference.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market Risk Information

The merchant energy business utilizes the sensitivity analysis methodology to disclose quantitative information for