CONNECTICUT LIGHT & POWER CO
Form 10-K
February 25, 2011

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, 2010
OR

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

For the transition period from ____________ to ____________

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

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

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 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**
ü	

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**
		ü

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**
	ü	

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. [**ü**]

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

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

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

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, 2010) was **$4,486,982,187** based on a closing sales price of **$25.48** per share for the 176,098,202 common shares outstanding on June 30, 2010. **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 as of January 31, 2011
Northeast Utilities Common shares, $5.00 par value	176,504,390 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 the Northeast Utilities Proxy Statement expected to be dated March 30, 2011	Part III

GLOSSARY OF TERMS

The following is a glossary of abbreviations or acronyms that are found in this report.

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS:

Boulos	E.S. Boulos Company
CL&P	The Connecticut Light and Power Company
HWP	HWP Company, formerly the Holyoke Water Power Company
NGS	Northeast Generation Services Company and subsidiaries
NGS Mechanical	NGS Mechanical, Inc.
NPT	Northern Pass Transmission LLC, a jointly owned limited liability company, held by NUTV and NSTAR Transmission Ventures, Inc. on a 75 percent and 25 percent basis, respectively
NUTV	NU Transmission Ventures, Inc.
NU or the Company	Northeast Utilities and subsidiaries
NU Enterprises	NU Enterprises, Inc., the parent company of Select Energy, NGS, NGS Mechanical, SECI and Boulos
NUSCO	Northeast Utilities Service Company
NU parent and other companies	NU parent and other companies is comprised of NU parent, NUSCO and other subsidiaries, including HWP, RRR (a real estate subsidiary), and the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, and Yankee Energy Financial Services Company)
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's Regulated companies, comprised of the electric distribution and transmission segments of CL&P, PSNH and WMECO, the generation activities of PSNH and WMECO, Yankee Gas, a natural gas local distribution company, and NPT
RRR	The Rocky River Realty Company
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc., a former subsidiary of NU Enterprises
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS:

CDEP	Connecticut Department of Environmental Protection
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
DPU	Massachusetts Department of Public Utilities
DPUC	Connecticut Department of Public Utility Control
FERC	Federal Energy Regulatory Commission
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission

SEC	Securities and Exchange Commission
USDEP	U.S. Department of Environmental Protection

OTHER:

2010 Healthcare Act	Patient Protection and Affordable Care Act
2010 Tax Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act
AFUDC	Allowance For Funds Used During Construction
AMI	Advanced metering infrastructure
ARO	Asset Retirement Obligation
C&LM	Conservation and Load Management
CAAA	Clean Air Act Amendments
CERCLA	The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980
CfD	Contract for Differences
CO_2	Carbon dioxide
CSC	Connecticut Siting Council
CTA	Competitive Transition Assessment
CWIP	Construction work in progress
CYAPC	Connecticut Yankee Atomic Power Company
EFSB	Massachusetts Energy Facilities Siting Board
EIA	Energy Independence Act
EMF	Electric and Magnetic Fields

EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse Gas
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Giga-watt Hours
HG&E	Holyoke Gas and Electric, a municipal department of the town of Holyoke, MA
HQ	Hydro-Québec, a corporation wholly-owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High voltage direct current
Hydro Renewable Energy	H.Q. Hydro Renewable Energy, Inc., a wholly-owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE	ISO New England, Inc., the New England Independent System Operator
KV	Kilovolt
KWh	Kilowatt-Hours
LNG	Liquefied natural gas
LOC	Letter of Credit
LRS	Last resort service
MGP	Manufactured Gas Plant
Millstone	Millstone Nuclear Generating station, made up of Millstone 1, Millstone 2, and Millstone 3. All three units were sold in March 2001.
MMBtu	One million British thermal units
Money Pool	Northeast Utilities Money Pool
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
MYAPC	Maine Yankee Atomic Power Company
NEEWS	New England East-West Solution
NO_x	Nitrogen oxide
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NPDES	National Pollutant Discharge Elimination System
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
NWPP	Northern Wood Power Project
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pension

PBOP Plan	Postretirement Benefits Other Than Pension Plan that provides certain retiree health care benefits, primarily medical and dental, and life insurance benefits
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PGA	Purchased Gas Adjustment
PPA	Pension Protection Act
RECs	Renewable Energy Certificates
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
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RNS	Regional Network Service
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
RTO	Regional Transmission Organization
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide

SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company
VIE	Variable interest entity
WWL Project	The construction of a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of Yankee Gas' LNG plant
YAEC	Yankee Atomic Electric Company
Yankee Companies	Connecticut Yankee Atomic Power Company, Yankee Atomic Electric Company and Maine Yankee Atomic Power Company

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

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THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

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

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, financial performance or growth and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify our forward-looking statements through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materially from actual results. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward-looking statements, including, but not limited to:

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actions or inaction by local, state and federal regulatory bodies

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changes in business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products and services

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changes in weather patterns

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changes in laws, regulations or regulatory policy

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changes in levels and timing of capital expenditures

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disruptions in the capital markets or other events that make our access to necessary capital more difficult or costly

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developments in legal or public policy doctrines

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technological developments

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changes in accounting standards and financial reporting regulations

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fluctuations in the value of our remaining competitive contracts

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actions of rating agencies

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The expected timing and likelihood of completion of the proposed merger with NSTAR, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, as well as the ability to successfully integrate the businesses, and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect and

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other presently unknown or unforeseen factors.

Other risk factors are detailed in our reports filed with the SEC and updated as necessary, and we encourage you to consult such disclosures.

All such factors are difficult to predict, contain uncertainties that may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see Item 1A*, Risk Factors,* included in this combined Annual Report on Form 10-K. This Annual Report on Form 10-K also describes material contingencies and critical accounting policies and estimates in the accompanying *Management s Discussion and Analysis* and *Combined Notes to Consolidated Financial Statements*. We encourage you to review these items.

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

PART I

Item 1.

Business

Please refer to the Glossary of Terms for definitions of defined terms and abbreviations used in this Annual Report on Form 10-K.

PROPOSED MERGER WITH NSTAR

On October 18, 2010, we and NSTAR announced that each company s Board of Trustees unanimously approved a Merger Agreement (the merger agreement) to combine the two companies. The transaction was structured as a merger of equals in a tax-free exchange. Upon the terms and subject to the conditions set forth in the merger agreement, at closing, NSTAR will become a wholly-owned subsidiary of NU. The post-transaction company will provide electric and natural gas energy delivery service to nearly 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England.

Under the terms of the merger agreement, NSTAR shareholders would receive 1.312 NU common shares for each common share of NSTAR that they own (the "exchange ratio"). The exchange ratio was structured to result in a no premium merger and is based on the average closing share price of each company's common shares for the 20 trading days preceding the announcement. Following completion of the merger, common shares of the post-transaction company will be owned approximately 56 percent by NU shareholders and approximately 44 percent by former NSTAR shareholders. We anticipate that we will issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger. Following the closing of the merger, our next quarterly dividend per common share will be increased to an amount that is equivalent to NSTAR s last quarterly dividend per common share paid prior to the closing, divided by the exchange ratio. Based on the last quarterly dividend paid by NSTAR of $0.425 per share, and assuming there are no changes to such dividend prior to the closing of the merger, that would result in NU s quarterly dividend being increased by approximately 18 percent to approximately $0.325 per share, or approximately $1.30 per share on an annualized basis as compared to NU's current annualized dividend of $1.10 per share. NU filed its joint proxy statement/prospectus with the SEC on January 5, 2011 and scheduled a special meeting of shareholders for March 4, 2011, at which shareholders will vote on whether to approve the merger.

Completion of the merger is subject to various customary conditions, including approval by holders of two-thirds of the outstanding common shares of each company and receipt of all required regulatory approvals, including those of the Massachusetts DPU, the FERC and the NRC. We received approval from the FCC on January 4, 2011, and on February 10, 2011, the applicable Hart-Scott-Rodino waiting period expired. Several intervening parties have applied to participate in the regulatory review of the merger and have raised various issues that they believe the regulatory agencies should examine in the course of the proceedings.

In November 2010, the DPUC issued a draft decision stating it lacked jurisdiction over the merger. In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned the DPUC to reconsider its draft decision. In January 2011, the DPUC issued an Administrative Order stating that it plans to hold a hearing to determine if it has jurisdiction over the merger. Oral arguments surrounding the draft decision were held in February 2011. The DPUC plans to hold an informational hearing at a date to be determined. In addition, legislation proposing to give the DPUC jurisdiction over the merger may be introduced in the Connecticut legislature.

THE COMPANY

NU, headquartered in Hartford, Connecticut, is a public utility holding company subject to regulation by FERC under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly-owned utility subsidiaries:

The Connecticut Light and Power Company (CL&P), a regulated electric utility that serves residential, commercial and industrial customers in parts of Connecticut;

Public Service Company of New Hampshire (PSNH), a regulated electric utility that serves residential, commercial and industrial customers in parts of New Hampshire and continues to own generation assets used to serve customers;

Western Massachusetts Electric Company (WMECO), a regulated electric utility that serves residential, commercial and industrial customers in parts of western Massachusetts; and

Yankee Gas Services Company (Yankee Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Connecticut.

NU also owns certain unregulated businesses through its wholly-owned subsidiary, NU Enterprises. As of December 31, 2010, NU Enterprises business consisted of (i) Select Energy s few remaining energy wholesale marketing contracts, which are being wound down, and (ii) NU Enterprises electrical contracting business.

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Although NU, CL&P, PSNH and WMECO each report their financial results separately, we also include information in this report on a segment, or line-of-business, basis - the distribution segment (which also includes the generation businesses of PSNH and WMECO and our natural gas distribution business) and the transmission segment. Our Regulated companies accounted for approximately 99 percent of our total earnings of $387.9 million for 2010, with electric distribution representing approximately 45 percent, natural gas distribution representing approximately 8 percent and electric transmission representing approximately 46 percent of consolidated earnings. The remaining 1 percent of our 2010 earnings comes from our competitive businesses.

REGULATED ELECTRIC DISTRIBUTION

General

NU s electric distribution segment consists of the distribution businesses of CL&P, PSNH and WMECO, which are primarily engaged in the distribution of electricity in Connecticut, New Hampshire and western Massachusetts, respectively, plus PSNH s regulated electric generation business and WMECO s solar generation. The following table shows the sources of 2010 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	**% of Total Revenues**
Residential	59%
Commercial	33%
Industrial	7%
Other	1%
Total	100%

A summary of changes in the Regulated companies retail electric sales (GWh) for 2010 as compared to 2009 on an actual and weather normalized basis (using a 30-year average) is as follows:

	2010	**2009**	**Percentage Increase/ (Decrease)**	**Weather Normalized Percentage (Decrease)**
Residential	14,913	14,412	3.5%	(0.7)%
Commercial	14,506	14,474	0.2%	(2.8)%
Industrial	4,481	4,423	1.3%	(1.5)%
Other	330	336	(1.4)%	(1.4)%
Total	34,230	33,645	1.7%	(1.7)%

Total retail electric sales for all three electric companies were higher in 2010 compared to 2009 due primarily to warmer than normal weather in the summer of 2010 and colder than normal weather in December 2010. Residential sales benefitted the most from the weather in 2010 and were higher for all three electric companies in 2010 compared to 2009.

On a weather normalized basis, retail sales for all three electric companies were lower in 2010 compared to 2009. We believe the decrease was due in part to increased conservation efforts by our customers and the continuing effects of the weak economy.

THE CONNECTICUT LIGHT AND POWER COMPANY - DISTRIBUTION

CL&P s distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2010, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 cities and towns in Connecticut. CL&P does not own any electric generation facilities. In 2010, CL&P had contracts to purchase the electric output from eighteen IPP generators. The term of two of these contracts ended in 2010. In 2011 the sixteen remaining generators are anticipated to provide approximately two million MWh per year through March 2015, with purchase quantities dropping significantly from 2015 through 2024, when the term of the last IPP contract ends. CL&P sells the output of these contracts into the ISO New England market, crediting customer energy charges with the proceeds. CL&P has entered into eleven contracts with renewable energy generators under a state program known as Project 150, and UI has entered into 2 other similar contracts under Project 150. CL&P and UI will share the costs and benefits of these contracts on an 80 percent and 20 percent basis, respectively. This cost sharing split is independent of the specific utility that is the counterparty to the contract. It is currently projected that the first of these renewable energy projects will commence commercial operation in 2011.

The following table shows the sources of 2010 electric franchise retail revenues for CL&P based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	61%
Commercial	32%
Industrial	6%
Other	1%
Total	100%

Rates

CL&P is subject to regulation by the Connecticut DPUC, which, among other things, has jurisdiction over its rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of facilities. CL&P's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. CL&P's retail rates include a delivery service component, which includes distribution, transmission, conservation, renewables, CTA, SBC and other charges that are assessed on all customers.

The CTA is a charge assessed to recover stranded costs associated with electric industry restructuring as well as various IPP contracts. The SBC recovers costs associated with various hardship and low income programs as well as payments to municipalities to compensate them for losses in property tax revenue due to decreases in the value of electric generating facilities resulting directly from electric industry restructuring. The CTA and SBC are annually reconciled to actual costs incurred, with any difference refunded to, or recovered from, customers.

Under state law, all of CL&P's customers are entitled to choose their energy suppliers, while CL&P remains their electric distribution company. Under "Standard Service" rates for customers with less than 500 KW of demand and "Supplier of Last Resort Service" rates for customers with 500 KW of demand or greater, CL&P purchases power for those customers who do not choose a competitive energy supplier and passes the cost to such customers through a combined GSC and FMCC on customers' bills. The combined GSC and FMCC charges for both types of service recover all of the costs of procuring energy from CL&P's wholesale suppliers and are adjusted periodically and reconciled semi-annually in accordance with the directives of the DPUC.

Although more CL&P customers chose competitive energy suppliers in 2010 than in 2009, CL&P continues to supply approximately 40 percent of its customer load at Standard Service or Supplier of Last Resort Service rates while the other 60 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on CL&P s delivery business or its operating income.

Distribution Rates: On June 30, 2010, the DPUC issued a final order in CL&P s most recent retail rate case approving annualized distribution rate increases of $63.4 million effective July 1, 2010 and an incremental $38.5 million effective July 1, 2011. The 2010 increase was deferred from customer bills until January 1, 2011 to coincide with the decline in revenue requirements associated with the final payment of CL&P s RRBs. In its decision, the DPUC also maintained CL&P s authorized distribution segment regulatory ROE of 9.4 percent. In 2010, CL&P earned a distribution segment regulatory ROE of 7.9 percent, compared to 7.3 percent in 2009, and expects to earn a distribution segment regulatory ROE of approximately 9 percent in 2011.

In May 2010, the Connecticut Legislature approved a state budget for the 2010-2011 fiscal year, which calls for the issuance by the state of Connecticut of up to $760 million of economic recovery revenue bonds (ERRBs) that would be amortized over eight years. These bonds will be repaid through a charge on the bills of customers of CL&P and other Connecticut electric distribution companies. For CL&P, the revenue to pay interest and principal on the bonds would come from a continuation of a portion of its CTA, which would have otherwise ended by December 31, 2010 with the final payment of the principal and interest on its RRBs, and the diversion of about one-third of the annual funding for C&LM programs beginning in April 2012. A lawsuit pending against the DPUC to prevent the issuance of the ERRBs is pending and several bills seeking to modify or prevent the issuance have been proposed before the state legislature.

On March 31, 2010, CL&P filed with the DPUC an AMI and dynamic pricing plan concluding that a full deployment of AMI meters accompanied by dynamic pricing options for all CL&P customers would be cost beneficial under a set of reasonable assumptions, identified as the "base case scenario." Under the base case scenario, capital expenditures associated with the installation of the meters are estimated at $296 million. CL&P has proposed beginning installation of meters in late 2012 and finishing in 2016.

CL&P has a transmission adjustment clause as part of its retail distribution rates, which reconciles on a semi-annual basis the transmission revenues billed to customers against the transmission costs of acquiring such services, thereby recovering all of its transmission expenses on a timely basis.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases energy to serve its Standard Service and Supplier of Last Resort Service loads from a variety of competitive sources through periodic RFPs. CL&P enters into supply contracts for Standard Service periodically for periods of up to three years to mitigate price volatility for its residential and small and medium load commercial and industrial customers. CL&P enters into supply contracts for Supplier of Last Resort service for larger commercial and industrial

customers every three months. Currently, CL&P has contracts in place with various suppliers for all of its Standard Service loads through 2011, 40 percent of expected load for 2012, and 10 percent of expected load for 2013. CL&P s contracts for its Supplier of Last Resort Service loads extend through the second quarter of 2011.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE - DISTRIBUTION

PSNH s distribution business (which includes its generation business) consists primarily of the generation, purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2010, PSNH furnished retail franchise electric service to approximately 497,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of primarily fossil-fueled electricity generation assets. Included in those generation assets is its 50 MW wood-burning Northern Wood Power Project at its Schiller Station in Portsmouth, New Hampshire, and approximately 70 MW of hydroelectric generation. PSNH also has contracts with 18 IPPs, the output of which it either uses to serve its customer load or sells into the market.

PSNH is constructing its Clean Air Project, a sulfur dioxide and mercury scrubber at its Merrimack coal-fired generation station, which is currently expected to cost $430 million. The project is scheduled for completion in mid-2012. PSNH will recover all related costs through its ES rates described below.

The following table shows the sources of 2010 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	54%
Commercial	36%
Industrial	9%
Other	1%
Total	100%

Rates

PSNH is subject to regulation by the NHPUC, which has jurisdiction over, among other things, rates, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service, management efficiency and construction and operation of facilities.

PSNH s ES rate recovers its generation and purchased power costs from customers on a current basis and allows for an ROE of 9.81 percent on its generation investment.

Under New Hampshire law, the SCRC allows PSNH to recover its stranded costs, including expenses incurred under mandated power contracts and other long-term investments and obligations. PSNH has financed a significant portion of its stranded costs through securitization by issuing RRBs secured by the right to recover these stranded costs from customers over time and recovers the costs of these bonds through the SCRC rate.

On an annual basis, PSNH files with the NHPUC an ES/SCRC reconciliation filing for the preceding year. The difference between ES/SCRC revenues and ES/SCRC costs are included in the ES/SCRC rate calculations and refunded to/recovered from customers in the subsequent period approved by the NHPUC.

The TCAM allows PSNH to recover on a fully reconciling basis its transmission related costs. The TCAM is adjusted July 1 of each year.

Distribution Rates: On June 28, 2010, the NHPUC approved a joint settlement of PSNH s rate case that had commenced in 2009, allowing a net distribution rate increase of $45.5 million on an annualized basis to be effective July 1, 2010, and annualized distribution rate adjustments projected to be a decrease of $2.9 million and increases of $9.5 million and $11.1 million on July 1 of each of the three subsequent years, respectively. PSNH agreed not to file a new distribution rate request that would be effective prior to July 1, 2015. During the term of the settlement, PSNH can only propose changes to its permanent distribution rate level when its 12-month distribution ROE falls below 7 percent for two consecutive quarters or certain specified external events, such as major storms, occur. If PSNH s 12-month ROE rolling average is greater than 10 percent, anything over the 10 percent level will be allocated 75 percent to customers and 25 percent to PSNH. The settlement also provided that the authorized regulatory ROE on distribution only plant will continue at the previously allowed level of 9.67 percent. PSNH s distribution segment regulatory ROE was 10.2 percent (including generation) in 2010, compared to 7.2 percent in 2009. We expect PSNH s distribution segment regulatory ROE will be approximately 9 percent in 2011.

PSNH's customers are entitled to choose competitive energy suppliers, with PSNH providing default energy service under its ES rate for those customers who do not elect to use a third party supplier. Prior to 2009, PSNH experienced only a minimal amount of customer migration. However, customer migration levels began to increase significantly in 2009 as energy costs decreased from their historic high levels and competitive energy suppliers with more pricing flexibility were able to offer electricity supply at lower prices than PSNH. By the end of 2010, approximately 2 percent of all of PSNH s customers (approximately 32 percent of load), mostly large commercial and industrial customers, had switched to competitive energy suppliers. The increased level of migration has caused an increase in the ES rate, as fixed costs of PSNH s generation assets must be spread over a smaller group of customers and lower sales volume. The customers that did not switch to a third party supplier, predominately residential and small commercial and industrial customers, are now paying a larger proportion of these fixed costs.

The NHPUC opened a proceeding in 2010 to consider the effect of customer migration on ES rates for customers, principally residential and small commercial and industrial customers, remaining on PSNH default energy service. As part of this docket, the NHPUC stated its intention to explore the interplay of customer choice, migration issues and power procurement options for PSNH.

PSNH cannot predict if the upward pressure on ES rates will continue into the future, as future customer migration levels, which are dependent on market prices and supplier alternatives, are uncertain. If future market prices once more exceed the average ES rate level, some or all of these customers on third party supply may migrate back to PSNH.

Sources and Availability of Electric Power Supply

During 2010, about 88 percent of PSNH s load was met through its own generation, long-term power supply provided pursuant to orders of the NHPUC, and contracts with third parties. The remaining 12 percent of PSNH's load was met by short-term (less than one year) purchases and spot purchases in the competitive New England wholesale power market. PSNH expects to meet its load requirements in 2011 in a similar manner.

WESTERN MASSACHUSETTS ELECTRIC COMPANY - DISTRIBUTION

WMECO s distribution business consists primarily of the purchase, delivery and sale of electricity to residential, commercial and industrial customers. At December 31, 2010, WMECO furnished retail franchise electric service to approximately 206,000 retail customers in 59 cities and towns in the western third of Massachusetts. Following electric industry restructuring in the 1990s, WMECO sold all of its generating facilities and now purchases its energy requirements from competitive suppliers. In 2009, pursuant to the Massachusetts Green Communities Act, WMECO was authorized to install 6 MW of solar energy generation in its service territory. In October 2010, WMECO completed construction of a 1.8 MW solar generation facility at a site in Pittsfield, Massachusetts, which began producing electricity in late 2010. In January 2011, WMECO announced its plans to develop a second solar generation facility at a site in Springfield, Massachusetts. This facility will accommodate 17,000 solar panels, producing up to 4.2 MW of solar energy. WMECO will sell all energy and other products from its solar generation facilities into the ISO New England market. WMECO had a contract with one IPP generator in 2010, the output of which WMECO sold into the ISO New England market. The term of this contract ended on December 31, 2010.

The following table shows the sources of 2010 electric franchise retail revenues based on categories of customers:

Sources of Revenue	**% of Total Revenues**
Residential	57%
Commercial	33%
Industrial	9%
Other	1%
Total	100%

Rates

WMECO is subject to regulation by the Massachusetts DPU, which has jurisdiction over, among other things, rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, acquisition of securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities. 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 recover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under state law, WMECO's customers are entitled to choose their energy suppliers, while WMECO remains their distribution company. WMECO purchases electric power from competitive suppliers for, and passes through the cost to, those customers who do not choose a competitive energy supplier (basic service). Basic service charges are adjusted and reconciled on an annual basis. Most of WMECO's residential and small commercial and industrial customers have continued to buy their power from WMECO at basic service rates. A greater proportion of large commercial and industrial customers have opted for a competitive energy supplier.

WMECO continues to supply approximately 50 percent of its customer load at basic service rates while the other 50 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on WMECO s delivery business or its operating income.

WMECO recovers certain costs through various tracking mechanisms in its retail rates, including transmission costs, pension costs and prudently incurred stranded costs (a portion of which have been financed through securitization by issuing RRBs) with periodic true-up adjustments.

Distribution Rates: On January 31, 2011, the DPU issued a final decision in WMECO s July 2010 rate application, granting a $16.8 million annualized rate increase in distribution revenues and an allowed ROE of 9.6 percent effective February 1, 2011. The DPU also authorized a full decoupling mechanism, whereby actual revenue billed by WMECO would be reconciled with WMECO s target revenue on an annual basis, WMECO s request to recover balances of certain active hardship account balances and the recovery of certain storm costs over five years. The DPU did not authorize rate recovery of a proposed $20 million average increase in WMECO s capital spending plan. WMECO s distribution segment regulatory ROE was 4.6 percent in 2010 compared to 8.4 percent in 2009. We expect WMECO s distribution segment regulatory ROE will be approximately 9 percent in 2011.

WMECO is subject to SQ metrics that measure safety, reliability and customer service, and WMECO pays any charges incurred for failure to meet such metrics to customers. WMECO will not be required to pay an assessment charge for its 2010 performance results as WMECO performed at target for all of its SQ metrics in 2010.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. However, the Company does not expect it will conduct a pilot prior to 2012.

Sources and Availability of Electric Power Supply

As noted above, WMECO does not own any generation assets (other than its recently constructed solar generation) and purchases its energy requirements from a variety of competitive sources through periodic RFPs. For basic service power supply, WMECO issues RFPs periodically, consistent with DPU regulations.

REGULATED GAS DISTRIBUTION YANKEE GAS SERVICES COMPANY

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 206,000 customers in 71 cities and towns), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in both 2010 and 2009 was approximately 52.5 Bcf. Yankee Gas provides firm natural gas sales service to retail customers who require a continuous natural gas supply throughout the year, such as residential customers who rely on gas for their heating, hot water and cooking needs, and commercial and industrial customers who choose to purchase natural gas from Yankee Gas. Retail natural gas service in Connecticut is partially unbundled: residential customers in Yankee Gas service territory buy gas supply and delivery only from Yankee Gas while commercial and industrial customers have choice in their gas suppliers. Yankee Gas offers firm transportation service to its commercial and industrial customers who purchase gas from sources other than Yankee Gas as well as interruptible transportation and interruptible gas sales service to those 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 also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which enables the company to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher.

The following table shows the sources of 2010 gas operating revenues based on categories of customers:

Sources of Revenue	**% of Total Revenues**
Residential	51%
Commercial	30%
Industrial	16%
Other	3%
Total	100%

A summary of firm natural gas sales in million cubic feet for Yankee Gas for 2010 and 2009 and the percentage changes in 2010 as compared to 2009 on an actual and weather normalized basis (using a 30-year average) is as follows:

Firm Natural Gas Sales (Mcf)

	2010	**2009**	**Percent Decrease/ Increase**	**Weather Normalized Percentage (Decrease)**
Residential	13,403	13,562	(1.2)%	4.9%
Commercial	14,982	14,063	6.6%	12.1%
Industrial	14,866	14,825	0.3%	1.7%
Total	43,251	42,450	1.9%	6.2%

Yankee Gas firm natural gas sales are subject to many of the same influences as our retail electric sales, but they have recently benefitted from a favorable price for natural gas relative to competing fuels resulting in commercial and industrial customers switching from interruptible service to firm service, and the addition of gas-fired distributed generation in Yankee Gas service territory. Actual firm natural gas sales in 2010 were higher than 2009 despite the milder weather during the first quarter 2010 heating season. Firm natural gas sales benefitted from these trends and from a large commercial customer who began to take service from Yankee Gas mid-way through the third quarter of 2009 and continued to take service throughout all of 2010.

In April 2010, Yankee Gas commenced construction of its WWL project, a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut coupled with the increase of vaporization output of its LNG plant. The project is expected to cost approximately $57.6 million. In 2010, approximately $26.6 million was spent on construction of the WWL project, which included construction of a segment of pipeline connecting the Cheshire and Wallingford distribution systems. The remainder of the pipeline construction and the expansion of the vaporization capacity of the LNG facility are expected to be completed in the fourth quarter of 2011

Rates

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

Distribution Rates: On January 7, 2011, Yankee Gas filed an application with the DPUC to raise natural gas distribution rates by $32.8 million, or 7.3 percent, to be effective July 1, 2011, and by an additional $13 million, or 2.8 percent, to be effective July 1, 2012. Among other items, Yankee Gas requested to maintain its current authorized ROE of 10.1 percent, that $57.6 million of costs associated with the WWL project be placed into rates, and that a substantial increase in capital funding to replace bare steel and cast iron pipe on Yankee Gas' system. A final decision is expected in June 2011. Yankee Gas regulatory ROE was 8.6 percent in 2010 compared to 6.6 percent in 2009. We expect Yankee Gas distribution segment regulatory ROE to be approximately 9 percent in 2011.

Sources and Availability of Natural Gas Supply

The DPUC requires that Yankee Gas meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its portfolio to meet firm customer needs under a design day scenario (defined as the coldest day in 30 years) and under a design year scenario (defined as the average of the four coldest years in the last 30 years). Yankee Gas LNG facility enables Yankee Gas to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher. Yankee Gas on-system stored LNG and underground storage supplies help to meet consumption needs during the coldest days of winter. Yankee Gas obtains its interstate capacity from the three interstate pipelines that currently directly serve Connecticut: the Algonquin, Tennessee and

Iroquois Pipelines. Yankee Gas has long-term firm contracts for capacity on TransCanada Pipelines Limited pipeline, Vector Pipeline, L.P., Tennessee Gas Pipeline, Iroquois Gas Transmission Pipeline, Algonquin Pipeline, Union Gas Limited, Dominion Transmission, Inc., National Fuel Gas Supply Corporation, Transcontinental Gas Pipeline Company, and Texas Eastern Transmission, L.P. pipelines. Yankee Gas considers such transportation arrangements adequate for its needs.

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 rules by which they participate in the wholesale markets and acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent of all market participants, has served since 2005 as the RTO of the New England transmission system. ISO-NE works to ensure the reliability of the system, administers, subject to FERC approval, the independent system operator tariff, oversees the efficient and competitive functioning of the regional wholesale power market and determines which costs of all regional major transmission facilities are shared by consumers throughout New England.

Wholesale Transmission Rates

Wholesale transmission revenues are recovered through formula rates that are approved by the FERC. Our transmission revenues are recovered from New England customers through ISO-NE charges which recover costs of transmission and other transmission-related services provided by all regional transmission owners, with a portion of those revenues collected from the distribution segments of CL&P, PSNH and WMECO.

FERC ROE Decision

Pursuant to a series of orders involving the ROE for regionally planned New England transmission projects, the FERC set the base ROE at 11.14 percent and approved incentives that increased the ROE to 12.64 percent for those projects that were in-service by the end of 2008. In addition, certain projects were granted additional ROE incentives by FERC under its transmission incentive policy. As a result, CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects. All appeals of FERC's orders on the ROE for New England transmission owners have been denied.

On November 17, 2008, the FERC issued an order granting certain incentives and rate amendments to National Grid and us for certain components of the proposed NEEWS project, which is described below. The approved incentives include (1) an ROE of 12.89 percent; (2) inclusion of 100 percent CWIP costs in rate base; and (3) full recovery of prudently incurred costs if any portion of NEEWS is abandoned for reasons beyond our control. Several parties have sought rehearing of this FERC order on which FERC has not yet acted.

Transmission Projects

NEEWS

CL&P and WMECO are continuing to develop and build the NEEWS project, which is comprised of GSRP, the Interstate Reliability Project and the Central Connecticut Reliability Project, and is estimated to cost $1.52 billion in the aggregate (approximately $1.45 billion reflecting the impact of UI s potential investment of up to approximately $69 million as discussed below). CL&P and WMECO commenced substation construction on GSRP in December 2010 and expect to begin overhead line construction in the first half of 2011. We expect GSRP to be placed in service in late 2013 at a cost of approximately $795 million.

CL&P is designing and building the Interstate Reliability Project in coordination with National Grid USA, whose segment of this phase will interconnect with CL&P s at the Connecticut-Rhode Island border. In August 2010, ISO-NE reaffirmed the need for the Interstate Reliability Project. We expect CL&P's share of the costs of this project to be $301 million and that the project will be placed in service in late 2015.

The timing of the Central Connecticut Reliability Project is expected to be twelve months behind the Interstate Reliability Project and cost approximately $338 million. ISO-NE continues to assess the need date for the Central Connecticut Reliability Project and we expect that ISO-NE will conclude its evaluation by mid-2011.

Included as part of NEEWS are $84 million of expenditures for associated reliability related projects, all of which have received siting approval and most are under construction. The in-service dates for these projects range from later this year through 2013.

Northern Pass Transmission Line Project

NPT is a limited liability company jointly formed by NU and NSTAR to construct, own and operate the Northern Pass transmission line, a new HVDC transmission line from the border of Canada and the United States to Franklin, New Hampshire that will interconnect at the border with a new HVDC transmission line being developed by HQ

TransEnergie, the transmission subsidiary of HQ. NUTV, a subsidiary of NU, holds a 75 percent interest in NPT, with NSTAR Transmission Ventures, Inc., a subsidiary of NSTAR, holding the remaining 25 percent. Consistent with FERC's February 11, 2011 order accepting the TSA between NPT and Hydro Renewable Energy that was filed December 15, 2011, NPT will charge Hydro Renewable Energy cost-based rates for firm transmission service over the Northern Pass line for a 40-year term. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project. Upon commercial operation, the ROE will be equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent based on a deemed capital structure for NPT of 50 percent debt and 50 percent equity.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE. The DOE application seeks permission for NPT to construct and maintain facilities that cross the U.S. border and connect to HQ TransEnergie's facilities in Canada. Assuming timely regulatory review and siting approvals, NPT expects to commence construction of the Northern Pass in 2013, with power flowing across the line in late 2015.

We currently estimate that our 75 percent share of the costs to build the Northern Pass transmission project will be approximately $830 million out of total expected costs of approximately $1.1 billion (including capitalized AFUDC).

Other Transmission Transactions

In July 2010, CL&P and UI entered into an agreement under which UI would acquire certain transmission assets within CL&P's portion of each of the NEEWS segments. Under the terms of the agreement, which has received approval from the FERC and the DPUC, UI will have the option to invest up to $69 million or an amount equal to 8.4 percent of CL&P's costs for the assets, which are expected to aggregate approximately $828 million.

On December 17, 2010, CL&P and CTMEEC, a non-profit municipal joint action transmission entity formed by several Connecticut municipal electric companies, entered into an agreement , subject to DPUC approval, under which CTMEEC would acquire a segment of CL&P s high voltage transmission lines in the town of Wallingford, Connecticut. The transaction was approved by FERC on January 31, 2011. The purchase price will be based on the net book value of the assets at the time of the closing of the sale in May 2011, projected to be approximately $42.3 million. CL&P will continue to operate and maintain the lines for CTMEEC.

Transmission Rate Base

Under our FERC-approved tariff, transmission projects generally enter rate base once they are placed in commercial operation. However, 100 percent of the NEEWS projects will enter rate base during their construction period. At the end of 2010, our transmission rate base was approximately $2.8 billion, including approximately $2.1 billion at CL&P, $341 million at PSNH and $269 million at WMECO. We forecast that our total transmission rate base will grow to approximately $4.8 billion by the end of 2015, including approximately $830 million at NPT.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The principal focus of our construction and capital improvement program is maintaining, upgrading and expanding our existing electric generation, transmission and distribution systems and our natural gas distribution system. Our consolidated capital expenditures in 2010 totaled approximately $1 billion, almost all of which ($967 million) was expended by the Regulated companies. The capital expenditures of these companies in 2011 are estimated to total approximately $1.2 billion, $477 million by CL&P, $284 million by PSNH, $287 million by WMECO and $113 million by Yankee Gas. This capital budget includes anticipated costs for all committed capital projects (i.e., generation, transmission, distribution, environmental compliance and others) and those we expect to become committed projects in 2011.

In 2010, CL&P s transmission capital expenditures totaled approximately $107 million, and its distribution capital expenditures totaled approximately $305 million. For 2011, CL&P projects transmission capital expenditures of approximately $137 million and distribution capital expenditures of approximately $337 million. During the period 2011 through 2015, CL&P plans to invest approximately $1 billion in transmission projects, the majority of which will be for NEEWS and $1.9 billon on distribution projects. If all of the distribution and transmission projects are built as proposed, CL&P s rate base for electric transmission is projected to increase from approximately $2.1 billion at the end of 2010 to approximately $2.6 billion by the end of 2015, and its rate base for distribution assets is projected to increase from approximately $2.3 billion to approximately $3.3 billion over the same period.

In 2010, PSNH's transmission capital expenditures totaled approximately $49 million, its distribution capital expenditures totaled approximately $84 million and its generation capital expenditures totaled $177 million. For 2011, PSNH projects transmission capital expenditures of approximately $59 million, distribution capital expenditures of approximately $113 million and generation capital expenditures of approximately $112 million. The bulk of the generation capital expenditures is for the Clean Air Project. During the period 2011 through 2015, PSNH plans to spend approximately $293 million on transmission projects, approximately $621 million on distribution projects, and $274 million on generation projects. If all of the distribution, generation and transmission projects are built as proposed, PSNH s rate base for electric transmission is projected to increase from approximately $341 million at the end of 2010 to approximately $540 million by the end of 2015, and its rate base for distribution and generation assets is projected to increase from approximately $1.2 billion to approximately $1.9 billion over the same period.

In 2010, WMECO's transmission capital expenditures totaled approximately $95 million, its distribution capital expenditures totaled approximately $33.1 million and solar generation expenditures were $10 million. In 2011, WMECO projects transmission capital expenditures of approximately $229 million, distribution capital expenditures of approximately $36 million and $22 million on solar generation. During the period 2011 through 2015, WMECO plans to spend approximately $732 million on transmission projects, with the bulk of that amount to be spent on GSRP, approximately $194 million on distribution projects and $46 million on solar generation. If all of the generation, distribution and transmission projects are built as proposed, WMECO s rate base for electric transmission is projected to increase from approximately $269 million at the end of 2010 to approximately $803 million by the end of 2015 and its rate base for distribution and generation assets is projected to increase from approximately $423 million to approximately $488 million over the same period.

In 2010, Yankee Gas capital expenditures totaled approximately $95 million. For 2011, Yankee Gas projects total capital expenditures of approximately $113 million, approximately $30 million of which is expected to be related to the WWL project, $37 million related to basic business activities such as relocation of conflicting gas facilities and the purchase of meters, tools and information technology; $30 million related to reliability improvements; and $16 million for load growth and new business requests. During the period 2011 through 2015, Yankee Gas plans on making approximately $587 million of capital expenditures, including approximately $30 million on the WWL project. Future capital spending will likely be affected by price differences between the cost of natural gas with respect to home heating oil, natural gas supply, new home construction, road reconstruction, regulatory mandates and business requirements. Excluding non-recurring major projects, NU expects that approximately 28 percent of Yankee Gas capital expenditures over the 2011-2015 period to be related to basic business activities, approximately 28 percent related to load growth and new business, and approximately 39 percent related to reliability initiatives, with the balance related to the WWL project. If all of Yankee Gas projects are built as proposed, Yankee Gas investment in its regulated assets is projected to increase from approximately $682 million at the end of 2010 to approximately $969 million by the end of 2015.

FINANCING

NU subsidiaries issued a total of $145 million in long-term debt in 2010. On March 8, 2010, WMECO issued $95 million of senior unsecured notes due March 1, 2020 carrying a coupon rate of 5.1 percent and on April 22, 2010, Yankee Gas issued $50 million of first mortgage bonds through a private placement with a maturity date of April 1, 2020 carrying a coupon rate of 4.87 percent.

In addition, on April 1, 2010, CL&P completed the remarketing of $62 million of tax-exempt secured PCRBs. The PCRBs carry a coupon rate of 1.4 percent until April 1, 2011, at which time CL&P expects to remarket the bonds.

On September 24, 2010, NU parent entered into a three-year $500 million unsecured revolving credit facility, and CL&P, PSNH, WMECO, and Yankee Gas jointly entered into a three-year $400 million unsecured revolving credit facility, both replacing five-year credit facilities on similar terms and conditions that were scheduled to expire on November 6, 2010. Like the previous facility, NU s new revolving credit facility allows NU parent to borrow on a short-term or long-term basis, or issue LOCs, up to $500 million in the aggregate. Under their new revolving credit facility, CL&P and PSNH are each able to draw up to $300 million, with WMECO and Yankee Gas each able to draw up to $200 million, all subject to the $400 million maximum aggregate borrowing limit.

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, PSNH, WMECO and Yankee Gas, comply with certain financial and non-financial covenants as are customarily included in such agreements, including maintaining a ratio of consolidated debt to total capitalization of no more than 65 percent. All such companies currently are, and expect to remain in compliance with these covenants.

We have annual sinking fund requirements of $4.3 million continuing in 2011 through 2012, the mandatory tender of $62 million of tax-exempt PCRBs by CL&P on April 1, 2011, at which time CL&P expects to remarket the bonds in the ordinary course. Neither NU nor any of its subsidiaries have any debt maturities until April 1, 2012.

In light of the 2010 Tax Act and the related cash flow benefits, we are currently reevaluating the timing of our previously planned NU common equity issuance. If we complete the proposed merger with NSTAR, we would no longer need to undertake the previously planned $300 million NU common equity issuance in 2012 nor issue any additional equity in the foreseeable future.

NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and several other New England electric utilities are stockholders in three inactive regional nuclear generation companies, CYAPC, MYAPC and YAEC (collectively, the Yankee Companies). The Yankee Companies have completed the physical decommissioning of their respective generation facilities and are now engaged in the long-term storage of their spent nuclear fuel. Each Yankee Company collects decommissioning and closure costs through wholesale FERC-approved rates charged under power purchase agreements with CL&P, PSNH and WMECO and several other New England utilities. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. The ownership percentages of CL&P, PSNH and WMECO in the Yankee Companies are set forth below:

	CL&P	PSNH	WMECO	Total
CYAPC	34.5%	5.0%	9.5%	49.0%

MYAPC	12.0%	5.0%	3.0%	20.0%
YAEC	24.5%	7.0%	7.0%	38.5%

Our share of the obligations to support the Yankee Companies under FERC-approved contracts is the same as the ownership percentages above.

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including the FERC, the SEC, 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, which has jurisdiction over CL&P and Yankee Gas, the NHPUC, which has jurisdiction over PSNH, and the DPU, which has jurisdiction over WMECO.

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. PSNH owns approximately 1,200 MW of generation assets and expects to spend approximately $430 million on its Clean Air Project, the installation of a wet flue gas desulphurization system at its Merrimack coal station to reduce its mercury and sulfur dioxide emissions. Compliance with additional environmental laws and regulations, particularly air and water pollution control requirements may cause changes in operations or require further 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 NPDES permit from the EPA or state environmental agency specifying the allowable quantity and characteristics of its effluent. States may also require additional permits for discharges into state waters. We are in the process of obtaining or renewing all required NPDES or state discharge permits in effect for our facilities. In each of the last three years, the costs incurred by the Company related to compliance with NPDES and state discharge permits have not been material. The Company expects to incur additional costs related to these permits in the future; however, due to uncertainty regarding the imposition of new or additional requirements, the Company is unable to accurately estimate such costs.

Air Quality Requirements

The CAAA, as well as New Hampshire law, impose stringent requirements on emissions of SO_2 and NO_X 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 capped NO_X, SO_2 and CO_2 emissions beginning in 2007. In addition, a 2006 New Hampshire law requires PSNH to install a wet flue gas desulphurization system, known as "scrubber" technology, to reduce mercury emissions of its coal fired plants by at least 80 percent (with the co-benefit of reductions in SO_2 emissions as well). The Clean Air Project addresses this requirement. PSNH began site work for this project in November 2008 and is scheduled to complete it by mid-2012.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the RGGI, a cooperative effort by ten northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fuel-fired electric generating plants. Because CO_2 allowances issued by any participating state will be usable across all ten RGGI state programs, the individual state CO_2 trading programs, in the aggregate, will form one regional compliance market for CO_2 emissions. A regulated power plant must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of a three-year compliance period that began in 2009.

Because neither CL&P nor WMECO currently own any generating assets (other than the solar facilities owned by WMECO, which do not emit CO_2), neither is required to acquire CO_2 allowances; however, the CO_2 allowance costs borne by generators that provide energy supply to CL&P and WMECO will likely be included in wholesale rates charged to them, which costs are then recoverable from customers.

PSNH anticipates that its generating units will emit between four million and five million tons of CO_2 per year after taking into effect the operation of PSNH s Northern Wood Power Project. Under the RGGI formula, this Project decreased PSNH s responsibility for reducing fossil-fired CO_2 emissions by approximately 425,000 tons per year, or almost ten percent. New Hampshire legislation provides up to 2.5 million banked CO_2 allowances per year for PSNH s fossil fueled generating plants during the 2009 through 2011 compliance period. These banked CO_2 allowances will initially comprise approximately one-half of the yearly CO_2 allowances required for PSNH s generating plants to comply with RGGI. Such banked allowances will decrease over time. PSNH expects to satisfy its remaining RGGI requirements by purchasing CO_2 allowances at auction or in the secondary market. The cost of complying with RGGI requirements is recoverable from PSNH customers.

Each of the states in which we do business also has RPS requirements, which generally require fixed percentages of energy supply to come from renewable energy sources such as solar, hydropower, landfill gas, fuel cells and other similar sources.

New Hampshire s RPS provision requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources, beginning in 2008 at four percent and ultimately reaching 23.8 percent by 2025. In 2010, the total RPS obligation was 7.5 percent of total generation supplied to customers. Energy suppliers, like PSNH, purchase RECs from producers that generate energy from a qualifying resource and use them to satisfy the RPS requirements. PSNH also owns renewable sources and uses both internally generated RECs and purchased RECs to meet its RPS obligations. To the extent that PSNH is unable to purchase sufficient RECs, it makes up the difference between the RECs purchased and its total obligation by making an alternative compliance payment for each REC requirement for which PSNH is deficient. The costs of both the RECs and alternative compliance payments do not impact earnings, as these costs are recovered by PSNH through its ES rates charged to customers.

Connecticut's RPS statute requires electricity suppliers to meet renewable energy standards, beginning with a four percent RPS in 2004. This percentage increases each year. For 2010, the requirement was 14 percent with goals of 19.5 percent by 2015 and 27 percent by 2020. CL&P is permitted to pass any costs incurred in complying with RPS on to customers through rates.

Massachusetts RPS program required electricity suppliers to meet a one percent renewable energy standard in 2003 and has a goal of 15 percent by 2015. For 2010, the requirement was five percent. WMECO is permitted to pass any costs incurred in complying with RPS on to customers through rates.

In addition, many states and environmental groups have challenged certain of the federal laws and regulations relating to air emissions as not being sufficiently strict. As a result, it is possible that state and federal regulations could be developed that will impose more stringent limitations on emissions than are currently in effect.

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws were implemented, utility companies often disposed of residues from operations by depositing or burying them on-site or disposing of them at off-site landfills or other facilities. Typical materials disposed of include coal gasification byproducts, fuel oils, ash, and other materials that might contain polychlorinated biphenyls or that otherwise might be hazardous. 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. We 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 these

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practices. At December 31, 2010, the liability recorded by us for our reasonably estimable and probable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $37.1 million, representing 58 sites. These costs could be significantly higher if remediation becomes necessary or when additional information as to the extent of contamination becomes available.

The most significant liabilities currently relate to future clean up costs at former MGP facilities. These facilities were owned and operated by our predecessor companies 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.

HWP, a wholly-owned subsidiary of NU, is continuing to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal electric utility, in 1902. HWP is at least partially responsible for this site and has already conducted substantial investigative and remediation activities. HWP's share of the remediation costs related to this site is not recoverable from customers.

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from 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, have concluded that the available body of scientific 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, we reduce 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.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues have received an increased focus from state governments and the federal government, particularly in recent years. The EPA has initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" and endanger public health and welfare and should be regulated. The largest source of greenhouse gas emissions in the U.S. is the electricity generating sector. The EPA has mandated GHG emission reporting beginning in 2012 for 2011 emissions for certain aspects of our business including stationary combustion, volume of gas supplied to large customers and fugitive emissions of SF-6 gas and methane.

We are continually evaluating the risks presented by climate change concerns and issues. Such concerns could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the generating facilities we own and operate as well as general utility operations. (See "Air Quality Requirements" in this section for information concerning RGGI) These could include federal "cap and trade" laws, or regulations requiring additional capital expenditures at our generating facilities. In addition, such rules or regulations could potentially impact the prices we pay for goods and services provided by companies directly affected by such rules or regulations. We would expect that any costs of these rules and regulations would be recovered from customers, but such costs could impact energy use by our customers.

Global climate change could potentially impact weather patterns such as increasing the frequency and severity of storms or altering temperatures. These changes could affect our facilities and infrastructure and could also impact energy usage by our customers.

FERC Hydroelectric Project Licensing

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 (iii) 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 a current claimed capability representing winter rates of approximately 71 MW, eight of which are licensed by the FERC under long-term licenses that expire on varying dates from 2017 through 2047. PSNH and its hydroelectric projects are subject to conditions set forth in such licenses, the Federal Power Act 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.

Licensed operating hydroelectric projects are not generally subject to decommissioning during the license term in the absence of a specific license provision that 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.   PSNH is not presently encountering any of these challenges.

EMPLOYEES

As of December 31, 2010, we employed a total of 6,182 employees, excluding temporary employees, of which 1,847 were employed by CL&P, 1,240 by PSNH, 354 by WMECO, 429 by Yankee Gas and 2,307 were employed by NUSCO. Approximately 2,212 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are members of the International Brotherhood of Electrical Workers and The United Steelworkers and are covered by 11 union agreements.

INTERNET INFORMATION

Our website address is www.nu.com. We make available through our website a link to the SEC's EDGAR website (http://www.sec.gov/edgar/searchedgar/companysearch.html), 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, 56 Prospect Street, Hartford, CT 06103.

Item 1A.

Risk Factors

In addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" included directly prior to Item 1, *Business,* above, we are subject to a variety of significant risks. 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 actions of regulators can significantly affect our earnings, liquidity and business activities.

The rates that our Regulated companies charge their respective retail and wholesale customers are determined by their state utility commissions and by FERC. These commissions also regulate the companies   accounting, operations, the issuance of certain securities and certain other matters. FERC also regulates their transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters. The commissions policies and regulatory actions could have a material impact on the Regulated companies financial position, results of operations and cash flows.

Our transmission, distribution and generation systems may not operate as expected, and could require unplanned expenditures, which could adversely affect our financial position, results of operations and cash flows.

Our ability to properly operate of our transmission, distribution and generation systems is critical to the financial performance of our business. Our transmission, distribution and generation businesses face several operational risks, including the breakdown or failure of or damage to equipment or processes (especially due to age); labor disputes; disruptions in the delivery of electricity, including impacts on us or our customers; increased capital expenditure requirements, including those due to environmental regulation; information security risk, such as a breach of our systems on which sensitive utility customer data and account information are stored; catastrophic events such as fires, explosions, or other similar occurrences; and other unanticipated operations and maintenance expenses and liabilities. The failure of our transmission, distributions and generation systems to operate as planned may result in increased capital investments, reduced earnings or unplanned increases in operation and maintenance costs. At PSNH, outages at generating stations may be deemed imprudent by state regulators resulting in disallowance of replacement power costs. Such costs that are not recoverable from our customers would have an adverse effect on our financial position, results of operations and cash flows.

Limits on our access to and increases in the cost of capital may adversely impact our ability to execute our business plan.

We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not obtained from our operating cash flow. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy could be adversely affected. In addition, higher interest rates would increase our cost of borrowing, which could adversely impact our results of operations. A downgrade of our credit ratings or events beyond our control, such as a disruption in global capital and credit markets, could increase our cost of borrowing and cost of capital or restrict our ability to access the capital markets and negatively affect our ability to maintain and to expand our businesses.

Our counterparties may not meet their obligations to us.

We are exposed to the risk that counterparties to various arrangements who owe us money, or have contracted to supply us with energy, coal, or other commodities or services, or who work with us as strategic partners, including on significant capital projects, will not be able to perform their obligations or, with respect to our credit facilities, fail to honor their commitments. Should any of these counterparties fail to perform their obligations, we might be forced to replace the underlying commitment at higher market prices and/or have to delay the completion of a capital project.

Should any lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements could decrease. In any such events, our financial position, results of operations, or cash flows could be adversely affected.

Changes in regulatory or legislative policy and/or regulatory decisions, difficulties in obtaining siting, design or other approvals, global demand for critical resources, environmental or other concerns, or construction of new generation may delay completion of or displace our planned transmission projects or adversely affect our ability to recover our investments or result in lower than expected rates of return.

Our transmission construction plans could be affected by new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions, delays in obtaining approvals or difficulty in obtaining critical resources required for construction. Any of such events could cause delays in our construction schedule adversely affecting our ability to achieve forecasted earnings.

The regulatory approval process for our transmission projects requires extensive permitting, design and technical activities. Various factors could result in increased costs and delay construction schedules. These include environmental and community concerns and design and siting issues. Recoverability of all such investments in rates may be subject to prudence review at the FERC. While we believe that all such costs have been and will be prudently incurred, we cannot predict the outcome of future reviews should they occur.

In addition, our transmission projects may be delayed or displaced by new generation facilities, which could result in reduced transmission capital investments, reduced earnings, and limited future growth prospects.

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

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

Increases in electric and gas prices and/or a weak economy, can lead to changes in legislative and regulatory policy promoting energy efficiency, conservation, and self-generation and/or a reduction in our customers ability to pay their bills, which may adversely impact our business.

Energy consumption is significantly impacted by the general level of economic activity and cost of energy supply. Economic downturns or periods of high energy supply costs typically can lead to the development of legislative and regulatory policy designed to promote reductions in energy consumption and increased energy efficiency and self-generation by customers. This focus on conservation, energy efficiency and self-generation may result in a decline in electricity and gas sales in our service territories. If any such declines were to occur without corresponding adjustments in rates, then our revenues would be reduced and our future growth prospects would be limited.

In addition, a period of prolonged economic weakness could impact customers ability to pay bills in a timely manner and increase customer bankruptcies, which may lead to increased bad debt expenses or other adverse effects on our financial position, results of operations or cash flows.

Connecticut, New Hampshire and Massachusetts have each investigated revenue decoupling as a mechanism to align the interests of customers and utilities relative to conservation. In Connecticut, the DPUC authorized decoupling through a rate design that is intended to recover greater distribution revenue through fixed charges, and proportionately less distribution revenue through usage-based charges. In New Hampshire, the NHPUC conducted a decoupling docket and determined that utilities were free to propose decoupling in the context of a rate case and demonstrate the effect decoupling would have on its risk profile and ROE. PSNH has not yet commenced such a proceeding. In Massachusetts, the DPU has required WMECO to adopt full decoupling in its January 31, 2011 rate decision. At this time it is uncertain what impact these decoupling mechanisms will have on our companies.

As a way to promote self-generation and reduce energy costs, Connecticut, Massachusetts, and New Hampshire have taken a greater interest in allowing customers to receive credit for generation produced at a customer-owned generating facility that exceeds their energy needs. In Massachusetts, in accordance with the Green Communities Act, the DPU adopted rules and regulations concerning net metering that will have this effect. Such rules provide a cost recovery mechanism for affected utilities to recover lost revenues. The Massachusetts DPU is expected to hold further proceedings to address net metering in early 2011. In Connecticut, the DPUC opened a docket to review existing state statutes and determine what limitations currently exist in state law concerning net metering. In addition, any legislation in Connecticut to promote self-generation and net metering could impact CL&P s financial position, results of operations or cash flows. In New Hampshire, new legislation dramatically changed the net metering rules in 2010. This new legislation is meant to encourage net metering from customers with small generators and also provides PSNH a cost recovery mechanism for lost distribution revenue.

Changes in regulatory and/or legislative policy could negatively impact regional transmission cost allocation rules.

The existing FERC-approved New England transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities. As new investment in regional transmission infrastructure occurs in any one state, its cost is shared across New England in accordance with relative benefits received. This regional cost allocation is set forth in the Transmission Operating Agreement signed by all of the New England transmission owning utilities. Effective February 1, 2010, this agreement can be modified with the approval of a majority of the transmission owning utilities and FERC. In addition, other parties, such as state regulators, may seek certain changes to the regional cost allocation formula, which could have adverse effects on the

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rates our distribution companies charge their retail customers. FERC is also considering policies to encourage the construction of transmission for renewable generation that could have the effect of imposing costs of inter-regional investment on New England customers.

Changes in regulatory or legislative policy or unfavorable outcomes in regulatory proceedings could jeopardize our full and/or timely recovery of costs incurred by our regulated distribution and generation businesses.

Under state law, our Regulated companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating 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 such costs incurred by our Regulated companies, such as for construction, operation and maintenance, 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 costs, thereby adversely affecting our financial position, results of operations or cash flows. Additionally, state legislators may enact laws that significantly impact our Regulated companies revenues, including by mandating electric or gas rate relief and/or by requiring surcharges to customer bills to support state programs not related to the utilities or energy policy. Such increases could pressure overall rates to our customers and our routine requests to regulators for rate relief.

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

PSNH meets most of its energy requirements through its own generation resources and fixed-price forward purchase contracts. PSNH s remaining energy needs are met primarily through spot market 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 energy to meet its requirements. PSNH recovers these costs through its ES rate, subject to a prudence review by the NHPUC. We cannot predict the outcome of future regulatory proceedings related to recovery of these costs.

Migration of customers from PSNH energy service to competitive energy suppliers could increase the cost to the remaining customers of energy produced by PSNH generation assets and decrease our revenues.

PSNH s ES rates have been higher than competitive energy prices offered to some customers in recent years, primarily due to lower natural gas prices. As a result, by the end of 2010, approximately 2 percent of PSNH s retail customers (representing approximately 32 percent of load), mostly large commercial and industrial customers, were buying their energy from competitive suppliers rather than from PSNH. The remaining retail customers are experiencing an increase in the cost of energy service supplied by PSNH by 5 percent to 7 percent due to migration of large commercial and industrial customers and the lower base in which to recover PSNH's fixed generation costs. This increase may in turn cause further migration and further increasing of PSNH energy service rates. This trend could lead to PSNH continuing to lose retail customers and increasing the burden of supporting the cost of its generation facilities on remaining customers and being unable to support the cost of its generation facilities through an ES rate.

The NHPUC is examining this issue in a proceeding in which hearings ended on December 1, 2010. PSNH has suggested transferring some fixed costs of the generation facilities into a nonbypassable charge while intervening competitive suppliers have proposed taking over the purchased power portion of the load not supplied by PSNH s generation. Others have also proposed having PSNH bid all of its generation facilities into the market while an RFP process supplies all of the power for PSNH s energy service. The NHPUC is considering further proceedings to explore these and other issues as well as the NHPUC authority to require PSNH to divest its generation facilities. It is not known what the results of such a proceeding would be, what PSNH may realize as a result of the sale or retirement of one or more of its generation facilities, or to what extent or manner the NHPUC would provide for recovery of any investment in its generation facilities.

Judicial or regulatory proceedings or changes in regulatory or legislative policy could jeopardize completion of, or full recovery of costs incurred by PSNH in constructing, the Clean Air Project.

Pursuant to New Hampshire law, PSNH is building the Clean Air Project at its Merrimack Station in Bow, New Hampshire. Several parties initiated legal proceedings challenging the project. These proceedings, or new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could result in increased costs to the project.

In addition, PSNH s investment in the project after it is completed is subject to prudence review by the NHPUC at the time the project is placed in service. A material prudence disallowance could adversely affect PSNH s financial position, results of operations or cash flows. While we believe we have prudently incurred all expenditures to date, we cannot predict the outcome of any prudency reviews should they occur. Our projected earnings and growth could be adversely affected were the NHPUC to deny recovery of some or all of PSNH s investment in the project.

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 parent 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 have developed strategic workforce plans to identify key functions and proactively implement plans to assure a ready and qualified workforce, but cannot predict the impact of these plans on our ability to hire and retain key employees.

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, solar storm activity 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, including cyber-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, results of operations or cash flows.

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 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, particularly as customers demand better and quicker response times to outages. 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.

Market performance or changes in assumptions could require us to make significant contributions to our pension and other post-employment benefit plans.

We provide a defined benefit pension plan and other post-retirement benefits for a substantial number of employees, former employees and retirees. Our future pension obligations, costs and liabilities are highly dependent on a variety of factors beyond our control. These factors include estimated investment returns, interest rates, health care cost trends, benefit changes, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs could increase significantly. In 2008 and 2009, due to the financial crisis, the value of our pension assets declined. As a result, we made a contribution of $45 million in 2010 and expect to make an approximate $145 million contribution in 2011. In addition, various factors, including underperformance of plan investments and changes in law or regulation, could increase the amount of contributions required to fund our pension plan in the future. Additional large funding requirements, when combined with the financing requirements of our construction program, could impact the timing and amount of future equity and debt financings and negatively affect our financial position, results of operations or cash flows.

Costs of compliance with environmental regulations, including climate change legislation, 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 that govern, among other things, air emissions, water discharges and the management of hazardous and solid waste. 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 existing legal requirements or legal requirements not yet adopted may increase in the future. An increase in such costs, unless promptly recovered, could have an adverse impact on our business and our financial position, results of operations or cash flows.

In addition, global climate change issues have received an increased focus from federal and state governments, which could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the power plants we own and operate as well as general utility operations. Although we would expect that any costs of these rules and regulations would be recovered from customers, their impact on energy use by customers and the ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time. The impact of these additional costs to customers could lead to a further reduction in energy consumption resulting in a decline in electricity and gas sales in our service territories, which would have an adverse impact on our business and financial position, results of operations or cash flows.

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. The cost impact of any such laws, rules or regulations would be dependent upon the specific requirements adopted and cannot be determined at this time. For further information, see Item 1, *Business* - "Other Regulatory and Environmental Matters," in this Annual Report on Form 10-K.

As a holding company with no revenue-generating operations, NU parent is dependent on dividends from its subsidiaries, primarily the Regulated companies, its bank facility, and its ability to access the long-term debt and equity capital markets.

NU parent is a holding company and as such, has no revenue-generating operations of its own. Its ability to meet its financial obligations associated with the debt service obligations on its debt and to pay dividends on its common shares is largely dependent on the ability of its subsidiaries to pay dividends to or to repay borrowings from NU parent; and/or NU parent s ability to access its credit

facility or the long-term debt and equity capital markets. Prior to funding NU parent, the Regulated companies have financial obligations that must be satisfied, including among others, their operating expenses, debt service, preferred dividends (in the case of CL&P) and obligations to trade creditors. Additionally, the Regulated companies could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from NU parent. Should the Regulated companies not be able to pay dividends to or repay funds due to NU parent or if NU parent cannot access its bank facilities or the long-term debt and equity capital markets, NU parent s ability to pay interest, dividends and its own debt obligations would be restricted.

Risks Related to the Proposed Merger with NSTAR

We may be unable to satisfy the conditions or obtain the approvals required to complete the merger or such approvals may contain material restrictions or conditions.

The merger is subject to approval by the shareholders of both NU and NSTAR and numerous other conditions, including the approval of various government agencies. Governmental agencies may not approve the merger or such approvals may impose conditions on the completion, or require changes to the terms of the merger, including restrictions on the business, operations or financial performance of the combined company, which could be adverse to the company's interests. These conditions or changes could also delay or increase the cost of the merger or limit the net income or financial prospects of the combined company.

We will be subject to business uncertainties and contractual restrictions while the merger is pending.

The work required to complete the merger may place a significant burden on management and internal resources. Management's attention and other company resources may be focused on the merger instead of on day-to-day management activities, including pursuing other opportunities beneficial to NU. In addition, while the merger is pending our business operations are restricted by the Agreement and Plan of merger to ordinary course of business activities consistent with past practice, which may cause us to forgo otherwise beneficial business opportunities.

We may lose management personnel and other key employees and be unable to attract and retain such personnel and employees.

Uncertainties about the effect of the merger on management personnel and employees may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, which could affect our financial performance.

The merger may not be completed, which may have an adverse effect on our share price and future business and financial results and we could face litigation concerning the merger, whether or not the merger is consummated.

Failure to complete the merger could negatively affect NU's share price, as well as our future business and financial results. In addition, purported class actions have been brought against us, NSTAR and others on behalf of holders of NSTAR common shares. If these actions or similar actions that may be brought are successful, the costs of completing the merger could increase, or the merger could be delayed or prevented. We cannot make any assurances that we will succeed in any litigation brought in connection with the merger. See Item 3, *Legal Proceedings*, in this Annual Report on Form 10-K for discussion of pending litigation related to the merger.

If the merger is not completed for certain reasons specified in the merger agreement, we may be required to pay NSTAR a termination fee of $135 million plus up to $35 million of certain expenses incurred by NSTAR. In addition, we must pay our own costs related to the merger including, among others, legal, accounting, advisory, financing and filing fees and printing costs, whether the merger is completed or not. Further, if the merger is not completed, we could be subject to litigation related to the failure to complete the merger or other factors, which may adversely affect our business, financial results and share price.

If completed, the merger may not achieve its intended results.

We entered into the merger agreement with the expectation that the merger would result in various benefits. If the merger is completed, our ability to achieve the anticipated benefits will be subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could adversely affect our business, financial results and share price.

Item 1B.

Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

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Item 2.

Properties

Transmission and Distribution System

As of December 31, 2010, our electric operating subsidiaries owned 31 transmission and 422 distribution substations that had an aggregate transformer capacity of 5,302,000 kilovolt amperes (kVa) and 29,861,000 kVa, respectively; 3,094 circuit miles of overhead transmission lines ranging from 69 KV to 345 KV, and 433 cable miles of underground transmission lines ranging from 69 KV to 345 KV; 34,957 pole miles of overhead and 3,054 conduit bank miles of underground distribution lines; and 539,379 underground and overhead line transformers in service with an aggregate capacity of 37,703,193 kVa.

Electric Generating Plants

As of December 31, 2010, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (kilowatts)
Total - Fossil-Steam Plants	5 units	1952-74	947,980
Total - Hydro-Conventional	20 units	1901-83	71,105
Total - Internal Combustion	5 units	1968-70	102,959
Total - Biomass - Steam Plant	1 unit	1954	45,816
Total PSNH Generating Plant	31 units		1,167,860

*

Claimed capability represents winter ratings as of December 31, 2010. The combined nameplate capacity of the generating plants is approximately 1,200 MW.

As of December 31, 2010, WMECO owned the following electric generating plant:

Type of Plant

	Number of Units	Year Installed	Claimed Capability** (kilowatts)
Total - Solar Fixed Tilt, Photovoltaic	1 unit	2010	1,800,000

** Claimed capability represents the direct current nameplate capacity of the plant.

CL&P did not own any electric generating plants during 2010.

Yankee Gas

As of December 31, 2010, Yankee Gas owned 28 active gate stations, approximately 200 district regulator stations and 3,239 miles of natural gas main pipeline. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, a propane facility in Kensington, Connecticut, and three additional propane facilities that are no longer in service and are expected to be sold in 2011.

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 Locational Installed Capacity (LICAP) costs. In addition, Section 83 of Public Act 07-242, "An Act Concerning Electricity and Energy Efficiency," states that if an existing electric generating plant located in Connecticut is offered for sale, then an electric distribution company, such as CL&P, would be eligible to purchase the generation plant upon obtaining prior approval from the DPUC and a determination by the DPUC that such purchase is in the public interest.

PSNH. The NHPUC, pursuant to statutory requirements, 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 distribution and transmission 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 DPU (then, the Department of Telecommunications and Energy) was required to define service territories for each distribution company, including WMECO. The DPU 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.

Yankee Gas. Yankee Gas holds valid franchises to sell gas in the areas in which Yankee Gas supplies gas service, which it acquired either directly or from its predecessors in interest. 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.

Yankee Companies v. U.S. Department of Energy

The Yankee Companies (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 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. In December 2006, the DOE appealed the decision and the Yankee Companies filed cross-appeals. The Court of Appeals disagreed with the trial court s method of calculation of the amount of the DOE s liability, among other things, and vacated the decision of the Court of Federal Claims and remanded the case to make new findings consistent with its decision. On September 7, 2010, the trial court issued its decision following remand and awarded CYAPC $39.7 million, YAEC $21.2 million and MYAPC $81.7 million. The DOE filed an appeal and the Yankee Companies cross-appealed. Briefs are due in the first quarter of 2011. The application of any damages that 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.

In December 2007, the Yankee Companies filed a second round of lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001 and 2002.

2.

Connecticut MGP Cost Recovery

In September 2006, CL&P and Yankee Gas (the NU Companies) filed a complaint against UGI Utilities, Inc. (UGI) in the U.S. District Court for the District of Connecticut seeking 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 allege 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 activity and expenditures at the sites are ongoing. A trial was held in April 2009.

On May 22, 2009, the court granted judgment in favor of the NU Companies with respect to the Waterbury-North site, and granted judgment in favor of UGI with respect to the remaining sites. Judgment was entered on March 31, 2010. On April 23, 2010, the NU Companies filed a Notice of Appeal with respect to the court s decision, which has been fully briefed. The Phase II trial, which would determine what portion of the remediation costs at the Waterbury-North site are attributable to UGI's control, is scheduled for August 31, 2011. Any recovery resulting from the case (following the appeal and the Waterbury-North complaint) would flow back to the NU Companies' customers, and the NU Companies would continue to seek recovery as appropriate of remediation and other associated costs with regard to the sites for which no recovery from UGI will be forthcoming.

3.

Litigation Related to the Proposed Merger with NSTAR

In October 2010, NSTAR, the members of the NSTAR board of trustees, NU, and two wholly-owned NU subsidiaries, NU Holding Energy 1 LLC and NU Holding Energy 2 LLC, were named defendants in eight lawsuits (since consolidated) filed in the Superior Court for Suffolk County, Massachusetts, and one lawsuit filed in federal court in the district of Massachusetts. The lawsuits, each of which was brought by a single shareholder, purport to be brought on behalf of classes of NSTAR shareholders opposed to the terms of the merger agreement. The original complaints made virtually identical allegations that, among other things, NSTAR s trustees breached their fiduciary duties by failing to maximize the value to be received by NSTAR s shareholders, and that the other defendants aided and abetted the NSTAR trustees breaches of fiduciary duties. Both the state and federal complaints sought and continue to seek, among other things, to enjoin defendants from consummating the merger and either rescission of the merger, to the extent it is completed, or monetary damages. On December 10, 2010, the state-court plaintiffs filed their consolidated amended complaint, which, in addition to the already-pending claims, alleged that the disclosures in the preliminary joint proxy statement/prospectus NU filed jointly with NSTAR, were insufficiently detailed, pointing to various aspects of the section entitled "The Merger." On January 6, 2011, NU and NSTAR each moved to dismiss the claims asserted against them for failure to state a claim. In addition, NU and NSTAR jointly moved for a protective order staying the discovery that some of the Plaintiffs had served contemporaneously with their complaints. On January 13, 2011, Plaintiffs moved the Court to expedite proceedings in anticipation of their making a subsequent motion for preliminary injunction to enjoin the March 4, 2011 shareholder vote. Plaintiffs also filed a purported "emergency" motion to obtain discovery from Lexicon Partners, NSTAR's financial advisors. NU and NSTAR opposed both motions, which the Court subsequently denied and scheduled a "litigation control" conference for February 28, 2011 "to address proper scheduling of any and all related motions anticipated by the parties." On February 11, 2011, Plaintiffs filed a motion for preliminary injunction seeking to enjoin the March 4, 2011 shareholder vote. NU and NSTAR will file their opposition to the motion on or before February 22, 2011 on the grounds that it lacks any legal or evidentiary basis. There have been no developments in the federal case, in which the plaintiff has never served NSTAR, NU, or any other defendant with his complaint. NU and NSTAR believe both the federal and state lawsuits are without merit and are defending the lawsuits vigorously.

4.

Bankruptcy of Independent Power Producer

On February 1, 2011, an independent power producer, AES Thames, L.L.C. (Thames), which is the counterparty to a CL&P electricity purchase agreement, filed a voluntary petition for bankruptcy in the U.S. Bankruptcy Court in Delaware (Case No. 11-10334). Thames owns and operates a 181 MW coal fired generation plant in Montville, Connecticut providing electric energy to CL&P and process steam to a nearby paperboard manufacturer. Citing market conditions and regulatory and legislative uncertainties, Thames had advised CL&P on January 24, 2011 that it was shutting the plant down for an undetermined period. Under an amendment to the electricity purchase agreement entered into in 1999, Thames agreed to supply CL&P with energy from the plant for a reduced price in exchange for a substantial prepayment. The electricity purchase agreement was due to expire in 2015. CL&P has appeared in the Delaware bankruptcy proceeding and intends to assert all available legal rights to protect its customers interests. Management cannot estimate the effects of this proceeding, but does not believe there will be a material impact on CL&P s financial position, results or operations or cash flows.

5.

Other Legal Proceedings

For further discussion of legal proceedings see the following sections of Item 1, *Business:* "- Regulated Electric Distribution," "-Regulated Gas Distribution - Yankee Gas Services Company," and "- Electric Transmission," for information about various state regulatory and rate proceedings, civil lawsuits related thereto, and information about proceedings relating to power, transmission and pricing issues; "- 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 THE REGISTRANT

The following table sets forth the executive officers of NU as of February 24, 2011. All of the Company s officers serve terms of one year and until their successors are elected and qualified:

Name	**Age**	**Title**
Jay S. Buth	41	Vice President - Accounting and Controller.
Gregory B. Butler	53	Senior Vice President and General Counsel.
Jean M. LaVecchia*	59	Vice President - Human Resources of NUSCO.
David R. McHale	50	Executive Vice President and Chief Financial Officer of NU.
Leon J. Olivier	62	Executive Vice President and Chief Operating Officer of NU.
James B. Robb*	50	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	65	Chairman of the Board, President and Chief Executive Officer of NU.

*

Deemed executive officer of NU pursuant to Rule 3b-7 under the Securities Exchange Act of 1934.

Jay S. Buth. Mr. Buth was elected Vice President - Accounting and Controller of NU, CL&P, PSNH and WMECO, effective June 9, 2009. Previously, Mr. Buth served as Controller, and Vice President and Controller at NJR Service Corporation, a subsidiary of New Jersey Resources Corporation, a gas utility holding company, from June 2006 to January 2009. He also served as Director - Finance at Allegheny Energy, Inc. from May 2004 to May 2006.

Gregory B. Butler. Mr. Butler was elected Senior Vice President and General Counsel of NU effective December 1, 2005, and of CL&P, PSNH and WMECO, subsidiaries of NU, effective March 9, 2006, and was elected a Director of CL&P, PSNH and WMECO April 22, 2009 and a Director of Northeast Utilities Foundation, Inc. effective December 1, 2002. Previously Mr. Butler served as Senior Vice President, Secretary and General Counsel of NU from August 31, 2003 to December 1, 2005 and Vice President, Secretary and General Counsel of NU from May 1, 2001 through August 30, 2003.

Jean M. LaVecchia. Ms. LaVecchia was elected Vice President - Human Resources of NUSCO, effective January 1, 2005 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009 and a Director of Northeast Utilities Foundation, Inc. effective January 30, 2007. Previously Ms. LaVecchia served as Vice President - Human Resources and Environmental Services from May 1, 2001 to December 31, 2004.

David R. McHale. Mr. McHale was elected Executive Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO, effective January 1, 2009, elected a Director of PSNH and WMECO, effective January 1, 2005, of CL&P effective January 15, 2007 and of Northeast Utilities Foundation, Inc. effective January 1, 2005. Previously, Mr. McHale served as Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO from January 1, 2005 to December 31, 2008 and Vice President and Treasurer of NU, PSNH and WMECO from July 1998 to December 31, 2004.

Leon J. Olivier. Mr. Olivier was elected Executive Vice President and Chief Operating Officer of NU effective May 13, 2008; He also has served as Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007; a Director of PSNH and WMECO since January 17, 2005 and a Director of CL&P since September 2001. Previously, Mr. Olivier served as Executive Vice President - Operations of NU from February 13, 2007 to May 12, 2008; 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; and President and Chief Operating Officer of CL&P from September 2001 to January 2005.

James B. Robb. Mr. Robb was elected Senior Vice President, Enterprise Planning and Development of NUSCO on September 4, 2007 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009. Previously, Mr. Robb served as Managing Director, Russell Reynolds Associates from December 2006 to August 2007; Entrepreneur in Residence, Mohr Davidow Ventures from March 2006 to November 2006; Senior Vice President, Retail Marketing, Reliant Energy, Inc. from December 2003 to December 2006; and Senior Vice President, Performance Management, Reliant Resources, Inc. from November 2002 to December 2003.

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

Item 4.

[RESERVED]

PART II

Item 5.

Market for the Registrants' Common Equity and Related Stockholder Matters

NU. Our common shares 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 sales prices for the past two years, by quarter, are shown below.

Year	Quarter	High	Low
2010	First	$ 28.00	$ 24.68
	Second	28.21	24.83
	Third	30.25	25.24
	Fourth	32.21	29.51
2009	First	$ 25.05	$ 19.45
	Second	22.40	19.99
	Third	24.72	21.38
	Fourth	26.33	22.54

There were no purchases made by or on behalf of our company 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, 2010.

As of January 31, 2011, there were 40,210 registered common shareholders of our company on record. As of the same date, there were a total of 195,808,704 common shares issued. There were no unallocated ESOP shares held in the ESOP trust as of December 31, 2010.

Pursuant to NU parent's Shareholder Rights Plan (the "Plan"), NU parent distributed to shareholders of record as of May 7, 1999, a dividend in the form of one common share purchase right (a "Right") for each common share owned by the shareholder. The Rights and the Plan expired at the end of the 10-year term on February 23, 2009.

On February 8, 2011, our Board of Trustees declared a dividend of 27.5 cents per share, payable on March 31, 2011 to shareholders of record as of March 1, 2011.

On October 12, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on December 31, 2010 to shareholders of record as of December 1, 2010.

On July 12, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on September 30, 2010 to shareholders of record as of September 1, 2010.

On April 13, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on June 30, 2010 to shareholders of record as of June 1, 2010.

On February 9, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on March 31, 2010 to shareholders of record as of March 1, 2010.

On October 13, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on December 31, 2009 to shareholders of record as of December 1, 2009.

On July 14, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on September 30, 2009 to shareholders of record as of September 1, 2009.

On April 14, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on June 30, 2009 to shareholders of record as of June 1, 2009.

On February 10, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on March 31, 2009 to shareholders of record as of March 1, 2009.

Information with respect to dividend restrictions for us, 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 Item 8, *Financial Statements and Supplementary Data*, in the *Combined Notes to Consolidated Financial Statements*, within this Annual Report on Form 10-K.

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

During 2010 and 2009, CL&P approved and paid $217.7 million and $113.8 million, respectively, of common stock dividends to NU.

During 2010 and 2009, PSNH approved and paid $50.6 million and $40.8 million, respectively, of common stock dividends to NU.

During 2010 and 2009, WMECO approved and paid $14.9 million and $18.2 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 Stockholder Matters*, included in this Annual Report on Form 10-K.

Item 6.

Selected Consolidated Financial Data

NU Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and common share information)		**2010**		**2009**		**2008**		**2007**		**2006**
Balance Sheet Data:										
Property, Plant and Equipment, Net	$	9,567,726	$	8,839,965	$	8,207,876	$	7,229,945	$	6,242,186
Total Assets		14,522,042		14,057,679		13,988,480		11,581,822		11,303,236
Total Capitalization (a)		8,627,985		8,253,323		7,293,960		6,667,920		5,879,691
Obligations Under Capital Leases (a)		12,236		12,873		13,397		14,743		14,425
Income Statement Data:										
Operating Revenues	$	4,898,167	$	5,439,430	$	5,800,095	$	5,822,226	$	6,877,687
Income from Continuing Operations		394,107		335,592		266,387		251,455		138,495
Income from Discontinued Operations		-		-		-		587		337,642
Net Income Attributable to Noncontrolling Interests		6,158		5,559		5,559		5,559		5,559
Net Income Attributable to Controlling Interests	$	387,949	$	330,033	$	260,828	$	246,483	$	470,578
Common Share Data:										
Basic Earnings Per Common Share:										

Income from Continuing Operations	$ 2.20	$ 1.91	$ 1.68	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	-	-	2.20
Net Income Attributable to Controlling Interests	$ 2.20	$ 1.91	$ 1.68	$ 1.59	$ 3.06
Diluted Earnings Per Common Share:					
Income from Continuing Operations	$ 2.19	$ 1.91	$ 1.67	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	-	-	2.19
Net Income Attributable to Controlling Interests	$ 2.19	$ 1.91	$ 1.67	$ 1.59	$ 3.05
Weighted Average Common Shares Outstanding					
Basic	176,636,086	172,567,928	155,531,846	154,759,727	153,767,527
Diluted	176,885,387	172,717,246	155,999,240	155,304,361	154,146,669
Dividends Declared Per Share	$ 1.03	$ 0.95	$ 0.83	$ 0.78	$ 0.73
Market Price - Closing (high) (b)	$ 32.05	$ 26.33	$ 31.15	$ 33.53	$ 28.81
Market Price - Closing (low) (b)	$ 24.78	$ 19.45	$ 19.15	$ 26.93	$ 19.24
Market Price - Closing (end of year) (b)	$ 31.88	$ 25.79	$ 24.06	$ 31.31	$ 28.16
Book Value Per Share (end of year)	$ 21.60	$ 20.37	$ 19.38	$ 18.79	$ 18.14
Tangible Book Value Per Share (end of year) (c)	$ 19.97	$ 18.74	$ 17.54	$ 16.93	$ 16.28
Rate of Return Earned on Average Common Equity (%) (d)	10.7	10.2	8.8	8.6	18.0
Market-to-Book Ratio (end of year) (e)	1.5	1.3	1.2	1.7	1.6
Capitalization:					
Total Equity	44%	44%	41%	44%	48%
Preferred Stock, not subject to mandatory redemption	1	1	2	2	2
Long-Term Debt (a)	55	55	57	54	50
	100%	100%	100%	100%	100%

(a)

Includes portions due within one year, but excludes RRBs for Long-Term Debt.

(b)

Market price information reflects closing prices as reflected by the New York Stock Exchange.

(c)

Common Shareholders' Equity adjusted for goodwill and intangibles divided by total common shares outstanding.

(d)

Net Income divided by the average change in Common Shareholders' Equity.

(e)

The closing market price divided by the book value per share.

See the *Combined Notes to the Consolidated Financial Statements* for a description of any accounting changes materially affecting the comparability of the information reflected in the table above**.**

CL&P Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2010	2009	2008	2007	2006
Operating Revenues	$ 2,999,102	$ 3,424,538	$ 3,558,361	$ 3,681,817	$ 3,979,811
Net Income	244,143	216,316	191,158	133,564	200,007
Cash Dividends on Common Stock	217,691	113,848	106,461	79,181	63,732
Property, Plant and Equipment, Net	5,586,504	5,340,561	5,089,124	4,401,846	3,634,370
Total Assets	8,287,585	8,364,564	8,336,118	7,018,099	6,321,294
Rate Reduction Bonds	-	195,587	378,195	548,686	743,899
Long-Term Debt (a)	2,583,102	2,582,361	2,270,414	2,028,546	1,519,440
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	10,613	10,956	11,207	13,602	14,264

PSNH Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2010	2009	2008	2007	2006
Operating Revenues	$ 1,033,439	$ 1,109,591	$ 1,141,202	$ 1,083,072	$ 1,140,900
Net Income	90,067	65,570	58,067	54,434	35,323
Cash Dividends on Common Stock	50,584	40,844	36,376	30,720	41,741
Property, Plant and Equipment, Net	2,053,281	1,814,714	1,580,985	1,388,405	1,242,378
Total Assets	2,889,840	2,697,191	2,628,833	2,106,969	2,071,276
Rate Reduction Bonds	138,247	188,113	235,139	282,018	333,831
Long-Term Debt (a)	836,365	836,255	686,779	576,997	507,099
Obligations Under Capital Leases (a)	1,428	1,670	1,931	1,141	1,356

WMECO Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2010	2009	2008	2007	2006
Operating Revenues	$ 395,161	$ 402,413	$ 441,527	$ 464,745	$ 431,509
Net Income	23,090	26,196	18,330	23,604	15,644
Cash Dividends on Common Stock	14,882	18,203	39,706	12,779	7,946
Property, Plant and Equipment, Net	817,146	705,760	624,205	559,357	526,094
Total Assets	1,199,559	1,101,800	1,048,489	991,088	988,693
Rate Reduction Bonds	43,325	58,735	73,176	86,731	99,428
Long-Term Debt (a)	400,288	305,475	303,868	303,872	261,777
Obligations Under Capital Leases (a)	83	105	126	-	-

(a)

Includes portions due within one year, but excludes RRBs for Long-Term Debt.

Item 7.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related combined notes included in this Annual Report on Form 10-K. References in this Annual Report to "NU," the "Company," "we," "us" and "our" refer to Northeast Utilities and its consolidated subsidiaries. All per share amounts are reported on a diluted basis.

Refer to the Glossary of Terms included in this Annual Report on Form 10-K for abbreviations and acronyms used throughout the combined notes to the consolidated financial statements.

The only common equity securities that are publicly traded are common shares of NU. The earnings and EPS of each business discussed below do not represent a direct legal interest in the assets and liabilities allocated to such business but rather represent a direct interest in our assets and liabilities as a whole. EPS by business is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to controlling interests of each business by the weighted average diluted NU common shares outstanding for the period. We use this non-GAAP financial measure to evaluate earnings results and to provide details of earnings results and guidance by business. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our businesses. This non-GAAP financial measure should not be considered as an alternative to our consolidated diluted EPS determined in accordance with GAAP as an indicator of operating performance.

The discussion below also includes non-GAAP financial measures referencing our 2010 earnings and EPS excluding expenses related to NU's proposed merger with NSTAR and certain non-recurring benefits from the settlement of tax issues as well as our 2008 earnings and EPS excluding a significant charge resulting from the settlement of litigation. We use these non-GAAP financial measures to more fully compare and explain the 2010, 2009 and 2008 results without including the impact of these non-recurring items. Due to the nature and significance of these items on Net Income, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to readers of this report in analyzing historical and future performance. These non-GAAP financial measures should not be considered as alternatives to reported Net Income Attributable to Controlling Interests or EPS determined in accordance with GAAP as indicators of operating performance.

Reconciliations of the above non-GAAP financial measures to the most directly comparable GAAP measures of consolidated diluted EPS and Net Income Attributable to Controlling Interests are included under "Financial Condition and Business Analysis-Overview-Consolidated" and "Financial Condition and Business Analysis-Future Outlook" in *Management's Discussion and Analysis*, herein. All forward-looking information for 2011 and thereafter provided in this *Management s Discussion and Analysis* assumes we will operate on a stand-alone basis, excluding the impacts of the proposed merger with NSTAR, unless otherwise indicated.

Financial Condition and Business Analysis

Proposed Merger with NSTAR:

On October 18, 2010, we and NSTAR announced that each company's Board of Trustees unanimously approved a Merger Agreement (the "agreement") to create a combined company that will be called Northeast Utilities. The transaction was structured as a merger of equals in a tax-free exchange. The post-transaction company will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England.

Under the terms of the agreement, NSTAR shareholders would receive 1.312 NU common shares for each NSTAR common share that they own (the "exchange ratio"). The exchange ratio was structured to result in a no premium merger based on the average closing share price of each company's common shares for the 20 trading days preceding the announcement. Based on the number of NU common shares and NSTAR common shares estimated to be outstanding immediately prior to the closing of the merger, upon such closing, NU shareholders will own approximately 56 percent of the post-transaction company and former NSTAR shareholders will own approximately 44 percent of the post-transaction company. It is anticipated that we would issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger.

Subject to the conditions in the agreement, our first quarterly dividend per common share declared after the completion of the merger will be increased to an amount that is equivalent, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing. Based on the last quarterly dividend paid by NSTAR, and assuming there are no changes to such dividend prior to the closing of the merger, this anticipated amount would be approximately $0.325 per share, or approximately $1.30 per share on an annualized basis.

Completion of the merger is subject to various customary conditions, including, among others, approval by holders of two-thirds of the outstanding common shares of each company and receipt of all required regulatory approvals. The companies anticipate that the regulatory approvals can be obtained to permit the merger to close in the second half of 2011. Special meetings of shareholders of both companies to approve the merger are scheduled for March 4, 2011. On November 24, 2010, NU and NSTAR filed a joint petition requesting Massachusetts DPU approval of their proposed merger by May 15, 2011. On January 5, 2011, a public hearing and procedural conference were held before the DPU. The schedule has subsequently been suspended pending a decision on the appropriate standard of review for the merger. On January 4, 2011, we received approval from the FCC, and on February 10, 2011, the applicable Hart-Scott-Rodino waiting period expired. On January 7, 2011, NU and NSTAR filed an application with the FERC, requesting approval of the merger by May 10, 2011.

In November 2010, the DPUC issued a draft decision stating that it lacked jurisdiction over the merger. In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned the DPUC to reconsider its draft decision. In January 2011, the DPUC issued an Administrative Order stating that it plans to hold a hearing to determine if it has jurisdiction over the merger. Oral arguments surrounding the draft decision were held in February 2011. The DPUC plans to hold an informational hearing at a date to be determined. In addition, legislation proposing to give the DPUC jurisdiction over the merger may be introduced in the Connecticut legislature.

Executive Summary

The following items in this executive summary are explained in more detail in this Annual Report:

Results:

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We earned $387.9 million, or $2.19 per share, in 2010, compared with $330 million, or $1.91 per share, in 2009. Improved results were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010, higher retail electric sales due to weather impacts, the non-recurring benefits from the settlement of tax issues in the fourth quarter of 2010, and our continued success in managing operation and maintenance costs. These benefits were partially offset by higher pension and storm-related expenses and expenses related to our proposed merger with NSTAR.

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Our Regulated companies earned $384 million, or $2.16 per share, in 2010, compared with $323.5 million, or $1.87 per share, in 2009.

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Earnings from the distribution segment of our Regulated companies (which also includes the generation businesses of PSNH and WMECO and the natural gas distribution business of Yankee Gas) totaled $206.2 million, or $1.16 per share, in 2010, compared with $159.2 million, or $0.92 per share, in 2009. Earnings from the transmission segment of our Regulated companies totaled $177.8 million, or $1.00 per share, in 2010, compared with $164.3 million, or $0.95 per share, in 2009.

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Our competitive businesses, which are held by NU Enterprises, earned $8.3 million, or $0.05 per share, in 2010, compared with $15.8 million, or $0.09 per share, in 2009. NU Enterprises recorded $0.7 million of after-tax mark-to-market gains in 2010, compared with $3.8 million of after-tax mark-to-market gains in 2009.

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NU parent and other companies recorded net expenses of $4.4 million, or $0.02 per share, in 2010, compared with net expenses of $9.3 million, or $0.05 per share, in 2009. The 2010 results include a fourth quarter non-recurring benefit of $15.7 million, or $0.09 per share, associated with the settlement of tax issues and a fourth quarter after-tax charge of $9.4 million, or $0.06 per share, associated with expenses related to NU s proposed merger with NSTAR.

Outlook:

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Excluding certain non-recurring costs related to our proposed merger with NSTAR of approximately $0.15 per share, we project consolidated 2011 earnings of between $2.25 per share and $2.40 per share. This projection includes distribution segment earnings of between $1.25 per share and $1.35 per share, transmission segment earnings of between $1.05 per share and $1.10 per share, and net expenses at NU parent and other companies of approximately $0.05 per share, excluding merger-related costs of approximately $0.15 per share. The number of outstanding NU common shares used to calculate this guidance is approximately 177 million shares. Results from our competitive businesses are factored into the NU parent and other companies results. This projection assumes we will operate on a stand-alone basis in 2011, although our proposed merger with NSTAR is expected to close in the second half of 2011.

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We project a compound average annual EPS growth rate through 2015 of between 6 percent and 9 percent using 2009 EPS of $1.91 per share as the base level. Assuming completion of our proposed merger with NSTAR, we expect our EPS growth rate will be at the higher end of this range.

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We project capital expenditures for 2011 through 2015 of approximately $6.6 billion (approximately $1.2 billion in 2011). During that time period, we expect our Regulated company rate base to increase from approximately $7.3 billion at the end of 2010 to approximately $11.4 billion at the end of 2015, excluding any impacts from the merger.

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On February 8, 2011, our Board of Trustees declared a quarterly common dividend of $0.275 per share, payable on March 31, 2011 to shareholders of record as of March 1, 2011, which equates to $1.10 per share on an annualized basis. Assuming completion of our proposed merger with NSTAR, based on the last quarterly dividend paid by NSTAR of $0.425 per share, and assuming there are no changes to such dividend prior to the closing of the merger, our first quarterly dividend per common share declared would be approximately $0.325 per share, or approximately $1.30 per share on an annualized basis.

Strategy, Regulatory and Other Items:

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On June 30, 2010, the DPUC issued a final decision in CL&P's distribution rate case that approved annualized rate increases of $63.4 million effective July 1, 2010 and an additional $38.5 million effective July 1, 2011. The decision approved CL&P s proposal to defer implementation of the first increase by six months until January 1, 2011 and maintained CL&P s authorized distribution segment regulatory ROE of 9.4 percent.

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On June 28, 2010, the NHPUC approved the distribution rate case settlement agreement among PSNH, the NHPUC staff and the Office of Consumer Advocate. Under the agreement, the settling parties agreed to a net annualized distribution rate increase of $45.5 million, effective July 1, 2010, and annualized distribution rate adjustments projected to be a decrease of $2.9 million and increases of $9.5 million and $11.1 million on July 1 of each of the three subsequent years. PSNH s authorized distribution business regulatory ROE remained at 9.67 percent.

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On January 31, 2011, the DPU issued a final decision in WMECO's distribution rate case that approved an annualized rate increase of $16.8 million effective February 1, 2011 and an authorized distribution segment regulatory ROE of 9.6 percent.

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On January 7, 2011, Yankee Gas filed an application with the DPUC to increase distribution rates by $32.8 million effective July 1, 2011 and by an additional $13 million effective July 1, 2012. Among other items, Yankee Gas requested to maintain its current authorized regulatory ROE of 10.1 percent. A final decision is expected in June 2011.

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On February 11, 2011, the FERC accepted without modification the TSA that NPT and Hydro Renewable Energy entered into in connection with the Northern Pass transmission project. Assuming timely receipt of other regulatory reviews and siting approvals, NPT expects to place the project in service in late 2015.

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CL&P and WMECO have received siting approvals in Connecticut and Massachusetts, respectively, for the first and largest component of our NEEWS project, GSRP, which involves the construction of 115 KV and 345 KV lines from Ludlow, Massachusetts, to Bloomfield, Connecticut. We commenced substation construction in December 2010, and expect to begin overhead line construction in the first half of 2011. We expect the cost of this project to be $795 million and to place the project in service in late 2013.

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Construction of PSNH s Clean Air Project at Merrimack Station was approximately 80 percent complete as of December 31, 2010 and is projected to cost approximately $430 million, which is approximately $27 million below the project s previously announced cost of $457 million. The project must be operational by July 1, 2013, but PSNH expects it will commence operations by mid-2012.

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On December 17, 2010, President Obama signed into law the 2010 Tax Act. We expect the 2010 Tax Act to provide NU with cash flow benefits of approximately $250 million in 2011 and approximately $450 million to $550 million over the period 2011 through 2013.

Liquidity:

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Cash capital expenditures totaled $954.5 million in 2010, compared with $908.1 million in 2009.

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Cash flows provided by operating activities in 2010 totaled $832.6 million, compared with $745 million in 2009 (amounts are net of RRB payments). The improved cash flows were due primarily to the absence in 2010 of costs incurred at PSNH and WMECO related to the major storm in December 2008 that were paid in the first quarter of 2009, a decrease in Fuel, Materials and Supplies attributable to a $31.8 million reduction in coal inventory levels at PSNH, and increases in amortization on regulatory deferrals within PSNH s ES and CL&P s CTA tracking mechanisms. Offsetting these favorable cash flow impacts was a $–––45 million contribution to our Pension Plan. Excluding the impact of our proposed merger with NSTAR, we project 2011 cash flows provided by operating activities, net of RRB payments, of approximately $950 million to $1 billion. The increase over 2010 is due primarily to the accelerated depreciation provisions of the 2010 Tax Act and the impact of the 2010 distribution rate case decisions. Those benefits are partially offset by projected 2011 contributions to our Pension Plan of approximately $145 million.

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Cash and cash equivalents totaled $23.4 million as of December 31, 2010, compared with $27 million as of December 31, 2009.

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On September 24, 2010, CL&P, PSNH, WMECO, and Yankee Gas jointly entered into a three-year $400 million unsecured revolving credit facility, replacing a five-year $400 million credit facility that was scheduled to expire on November 6, 2010. On September 24, 2010, NU parent entered into a three-year $500 million unsecured revolving credit facility, replacing a five-year $500 million credit facility that was scheduled to expire on November 6, 2010. Both new revolving credit facilities expire on September 24, 2013. As of December 31, 2010, we had $600.9 million of aggregate borrowing availability on our revolving credit lines, as compared to $702.8 million as of December 31, 2009.

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We issued $145 million of new long-term debt in 2010, consisting of $95 million by WMECO and $50 million by Yankee Gas. Additionally, CL&P remarketed $62 million of tax-exempt PCRBs. In 2011, in addition to remarketing the CL&P $62 million PCRBs, we expect to issue approximately $260 million of long-term debt comprised of $160 million by PSNH and $100 million by WMECO in the second half of 2011. We have no debt maturities until April 2012.

Overview

Consolidated: We earned $387.9 million, or $2.19 per share, in 2010, compared with $330 million, or $1.91 per share, in 2009 and $260.8 million, or $1.67 per share, in 2008. Improved results were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010, higher retail electric sales due to warmer than normal summer weather and colder than normal December 2010 weather, the non-recurring benefits from the settlement of tax issues in the fourth quarter of 2010, lower uncollectibles expense, our continued success in managing operation and maintenance costs, and increased earnings in the transmission segment. These benefits were partially offset by higher pension and storm-related expenses, expenses related to our proposed merger with NSTAR, charges associated with the enactment of the 2010 Healthcare Act, and lower earnings at our competitive businesses. Due primarily to weather impacts, retail electric sales were up 1.7 percent in 2010 compared with 2009.

A summary of our earnings by business, which also reconciles the non-GAAP financial measures of consolidated non-GAAP earnings and EPS, as well as EPS by business, to the most directly comparable GAAP measures of consolidated Net Income Attributable to Controlling Interests and diluted EPS, for 2010, 2009 and 2008 is as follows: