W. Dean

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 10, 1993

Docket No. 50-245, 50-336
50-427, 50-213

MEMORANDUM FOR: T. Murley, F. Miraglia, W. Russell, L. J. Callan, D. Crutchfield, W. Travers, F. Gillespie, S. Varga, J. Calvo, G. Lainas, J. Roe, J. Zwolinski, E. Adensam, B. Grimes, J. Wiggins, B. D. Liaw, A. Thadani, M. Virgilio, C. Rossi, R. Zimmerman, B. Boger, C. Thomas, F. Congel, E. Butcher, W. Bateman, EDO, M. Slosson, Operations Center, R. Cooper, RGI, E. Merschoff, RGII, E. Greenman, RGIII, A. Bill Beach, RGIV, K. Perkins, RGV

THRU: John F. Stolz, Director
Project Directorate I-4
Division of Reactor Projects - I/II

FROM: James W. Andersen, Acting Project Manager
Project Directorate I-4
Division of Reactor Projects - I/II

SUBJECT: DAILY HIGHLIGHT - MILLSTONE NUCLEAR POWER STATION, UNITS 1, 2 AND 3, AND THE HADDAM NECK PLANT

NORTHEAST UTILITIES REORGANIZATION

On November 8, 1993, the Executive Vice President-Nuclear of Northeast Utilities (NU), John F. Opeka, announced a restructuring within the nuclear group. All the appointments are effective as of December 5, 1993.

Donald B. Miller, Jr. - Senior Vice President, Millstone Station. Since 1990, he has been Vice President - Peach Bottom at Philadelphia Electric. Before that, he worked for NU for almost 12 years. He replaces Steve Scace.

Steven E. Scace - Vice President, Nuclear, Operations Services. He replaces Wayne Romberg. John F. Opeka, Executive Vice President-Nuclear, will assume the responsibility for the Vice President, Nuclear, Operations Services position, as well as his own position, until December 5, 1993.

L. A. Chatfield - Director Nuclear Safety Concerns. He replaces D. G. Diedrick who will become the Director of Special Projects.

Richard M. Kacich - Director Nuclear Planning, Licensing and Budgeting. He previously was the Director Nuclear Licensing. The position of Director Nuclear Planning and Budgeting was eliminated and the functions were combined with Nuclear Licensing.

Eric A. DeBarba - Vice President-Nuclear Engineering Services. He currently held this position, however, the Engineering Managers for all four plants now report directly to him vice the specific Unit Directors. The engineering departments for all four plants have been reorganized and have new directors.

Michael B. Brown - Director Nuclear Training. He replaces Malcolm Black. This change is effective November 8, 1993.

Numerous other changes occurred below the director level as a result of the engineering integration and restructuring. The Unit Directors for each plant did not change.

James W. Andersen, Acting Project Manager
Project Directorate I-4
Division of Reactor Projects - I/II

cc: All NRR PDs
A. Chaffee, OEAB
G. Zech, RPEB
D. Norkin, RSIB

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY
WESTERN MASSACHUSETTS ELECTRIC COMPANY
HOLYOKE WATER POWER COMPANY
NORTHEAST UTILITIES SERVICE COMPANY
NORTHEAST NUCLEAR ENERGY COMPANY

MEMO

Oct. 12, 1993

EAD-93-099

TO: Nuclear Directors and Managers

FROM: E. A. DeBarba Ed DeBarba

SUBJECT: Engineering Integration

As the development of Engineering Integration has proceeded, its status has been communicated through various Nuclear News and TieLine articles, and a memo from J.F. Opeka. Now that the final phase of this project is nearing completion I want to share with you a summary of the recommendations and implementation plans developed by the Integration Team and generally adopted by senior nuclear management earlier this week. I expect that the final version of the Integration Report will be completed by Oct. 15. Until the entire document is available I have attached those portions which contain many of the key elements which should be communicated with your employees.

The enclosed information describes how engineering will be restructured under one centralized and four unit directors. Some detail on the roles and responsibilities of the various engineering functions is also provided. Our objective is for an expeditious yet carefully planned transition to this new organization. This will begin with the selection of Directors through the use of the Nuclear Management Development Program. These new Directors will play a key role in implementing many of the approximately 80 integration recommendations over the next several months. Perhaps the most important of these tasks will be the selection of the most qualified candidates for new positions. The selection process which will be used is based on the model used throughout the corporation. Implementation plans target the naming of Directors and Managers for early November. Supervisors and other employees would be selected for the remaining positions around the end of November. The actual reassignment and relocation of employees, however, will likely be phased throughout 1994 depending on current work commitments, outage schedules, the availability of facilities, etc.

I truly believe that successful implementation of the recommendations developed in this integration effort is our key to becoming an even more effective organization. That success will naturally depend on the full support and cooperation of you and your people. I therefore hope you will discuss the enclosed information with your employees. As we proceed with the implementation process it is my intent to fully communicate all aspects of the reorganization with you. As additional information becomes available, including the final integration report, I will arrange group meetings in which they can be discussed.

cc: Nuclear Vice-Presidents

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ENGINEERING INTEGRATION REPORT
EXECUTIVE SUMMARY

This section of the engineering integration report provides an executive summary or overview of the project's recommendations.

Overall, the recommendations contained in this report should lead to significant improvements in the effectiveness of engineering support to the Millstone and Haddam Neck units. Moreover, they should lead to improvements in efficiency and productivity, supporting corporate goals to reduce costs while maintaining or improving current levels of quality and safety.

The report contains about 80 recommendations to improve the nuclear engineering function. The major changes to the engineering function that are recommended in the report are summarized below.

- o A new position of Engineering Director should be created at each unit.
  - Addition of the Director positions will improve accountability for engineering issues arising at the units, and provide a higher decision-making authority for engineering issues at each unit.
  - This addition will also allow the Unit Directors to focus on operations and maintenance. It must remain clear that the Unit Directors remain accountable and responsible for operational decisions at the units, and that the Unit Directors and Engineering Directors must work closely together and share common goals.

- o The unit engineering and unitized Project Services organizations should be combined into one department at each unit, reporting to the new Directors Engineering for each unit.
  - Separation of design and system engineering functions should be retained at the Manager level, to foster continued control over the design basis of each unit.
  - Current levels of engineering and technical support in the Maintenance and I&C organizations should be retained.

- Engineering roles and responsibilities should be clarified, as described in detail in the report.

- The consolidation of currently separate organizations under one management structure should lead to improved productivity as handoffs are reduced and people work more closely together to solve problems.

o The responsibilities, expertise, and size of the off-site corporate engineering organization in Berlin should be reduced, while the unit engineering organizations should be made essentially self-sufficient for design work.

  - The corporate engineering organization should focus only on strategic issues and provision of specialized expertise such as fuels work and PRA.

  - More routine support functions (such as stress analysis) should be transferred to the unit engineering organizations.

  - The reduction in size of the Corporate engineering organization will essentially be offset by increases in unit engineering staffing.

  - The net impact of integration is expected to be a reduction of approximately 100 positions - including open PVR's, contractors and possibly some NU personnel.

o Those functions that primarily support maintenance rather than engineering (such as construction, NDE, vibration analysis, etc.) should be transferred out of the corporate engineering organization; the maintenance assessment team will determine whether to keep these functions and personnel within a centralized or unit-based organization.

  - Maintenance Engineering functions (RCM, maintenance rule) should not be transferred into engineering; these functions will also be dispositioned by the maintenance assessment team.

  - Procurement Engineering should remain a part of Nuclear Operations Services.

o Nuclear Safety Engineering should remain in the Quality Services Department.

- o The remaining engineering functions in Berlin should be combined into one Department. Management and supervisory positions should be combined to provide appropriate spans of control.

  - In addition, the management of this function should continue to examine nuclear engineering for additional savings not identified as part of the engineering integration review.

- o The four Engineering Directors of the units and the Corporate Engineering Director should all report to the Vice President of Nuclear Engineering.

  - A centralized reporting relationship will promote commonality and sharing of lessons learned across units, and allow for future sharing of resources and expertise when needed.

- o Staffing in the unit design groups should be reduced to reflect improvements in the new design change process and expected reductions in the number of design changes.

- o Implementation of the systems engineering concept should be accelerated somewhat at Millstone; the proposed PEP staffing numbers for systems engineers can be reduced somewhat at Millstone, taking into account clarification of roles and responsibilities, and lessons learned from benchmarking and the experience to date at Connecticut Yankee.

- o Program responsibilities should be clarified: the Corporate organization will be responsible only for initial program development and program oversight; the unit engineering organizations will be responsible for implementation planning, implementation, and maintenance.

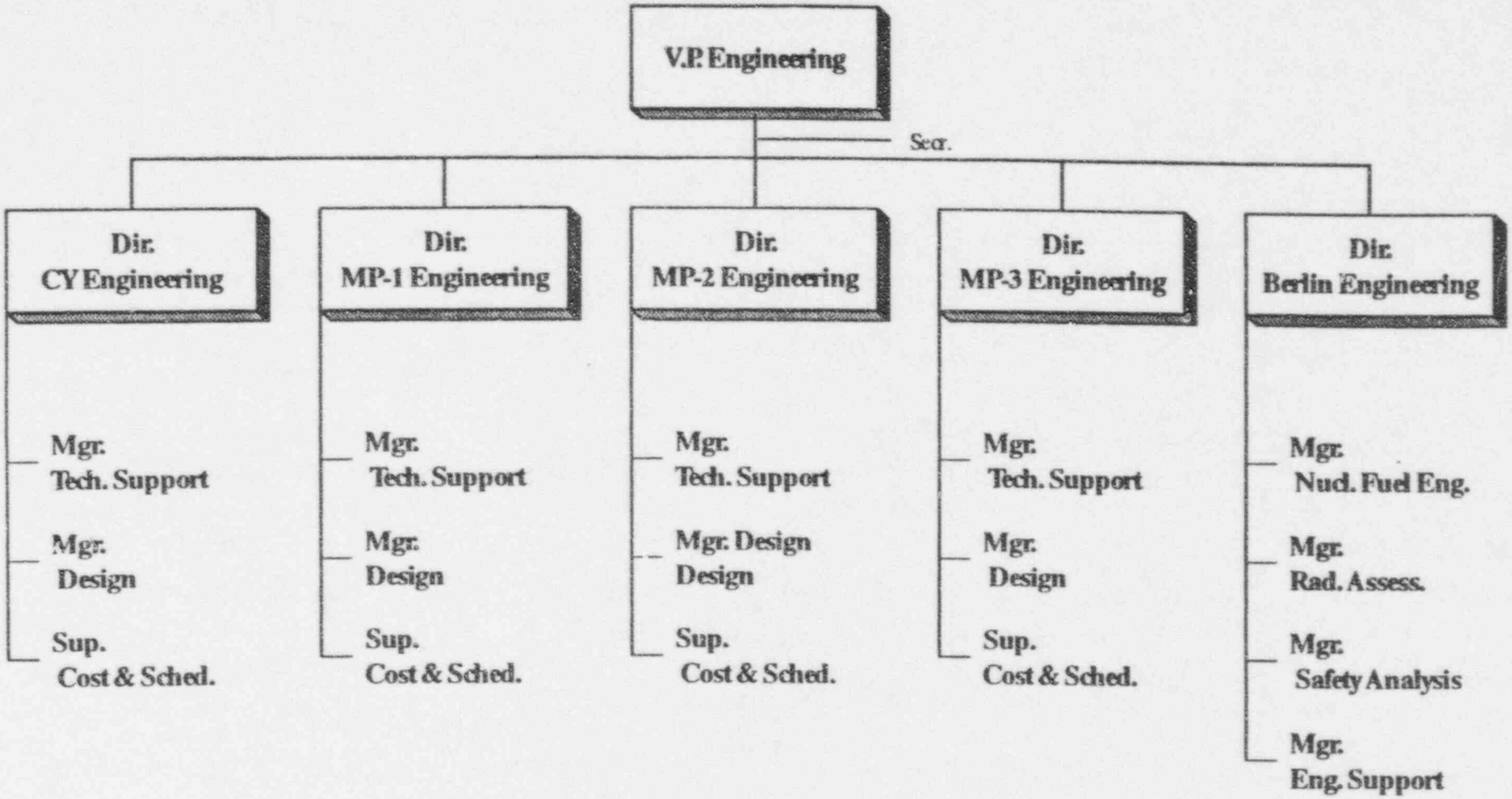
- o Methods of controlling engineering work and controlling contractors should be improved, to enhance the businesslike culture of the nuclear group.

  - In addition, where appropriate, "outsourcing" of engineering support should be considered.

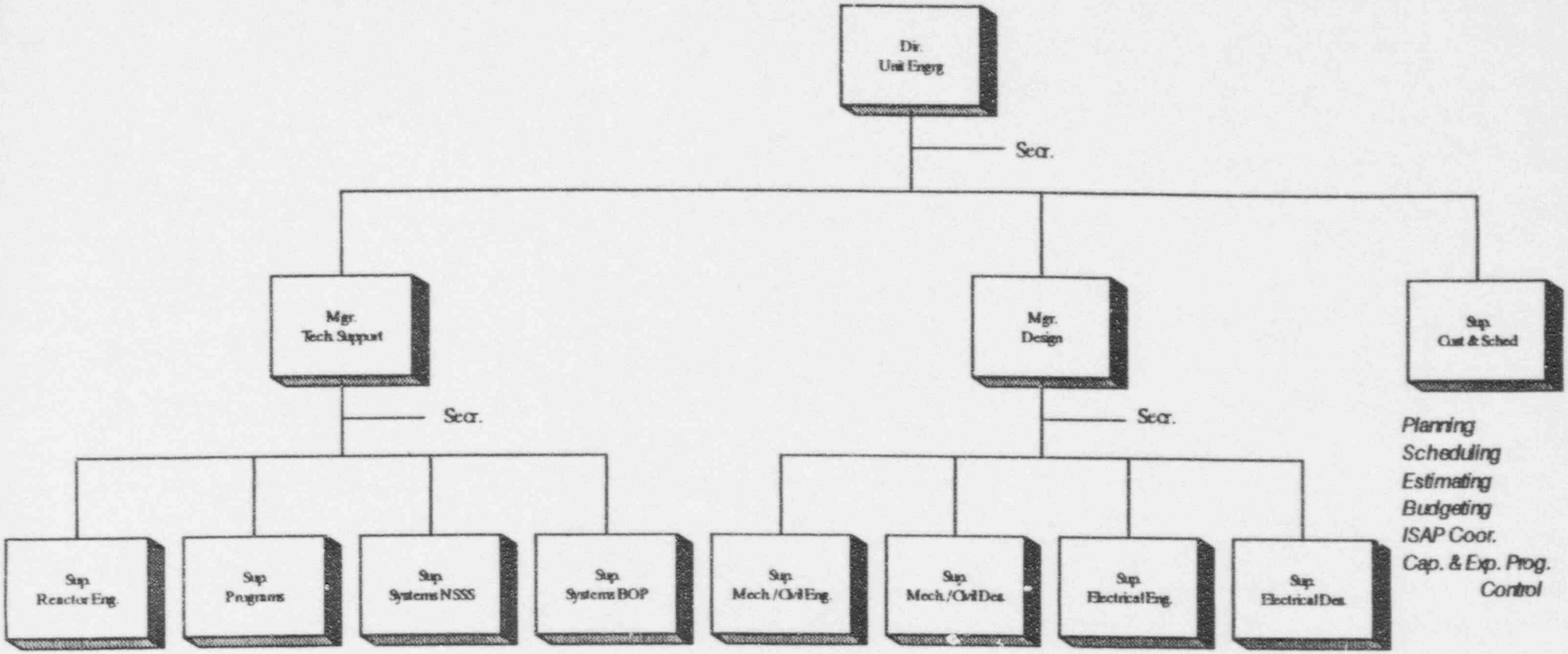
Taken together, these recommendations for improvement should yield significant savings to the Nuclear Group. Savings will be derived from the elimination of some open PVRs and the ability to fill other vacancies with NU personnel, and through the elimination of some long-term contractors or the replacement of them with NU personnel. (Issue ER-3 provides recommendations on matching personal qualifications to positions to ensure that we place people in the right positions and provide appropriate training to people who need it.)

The next section of this report provides detailed organization charts and a staffing summary for the recommended organization. The main body of the report presents the findings and conclusions for each issue, together with specific recommendations. The final section of the report contains an implementation plan that assigns responsibility for each recommendation and target completion dates.

PROPOSED ENGINEERING ORGANIZATION



Unit Engineering Structure



Planning
Scheduling
Estimating
Budgeting
ISAP Coor.
Cap. & Exp. Prog. Control

Core Perf. Monit.
Fuel Mgt. & Contr.
Proced. Rev. & Input
Computer Supp.(CY)
BOP Monitoring
Special Nucl. Matls. Program

Fire Prot.
Sec. XI
ISI / IST
E / C
MOV
S/G Insp.
Ck. Valves

Sys. Expert / Single Point of Contact
Monitor / Trend Sys. Perf.
Sys. Investigations / Troubleshoot
Coor. Non-routine Activity on Sys.
Proced. Review & Input

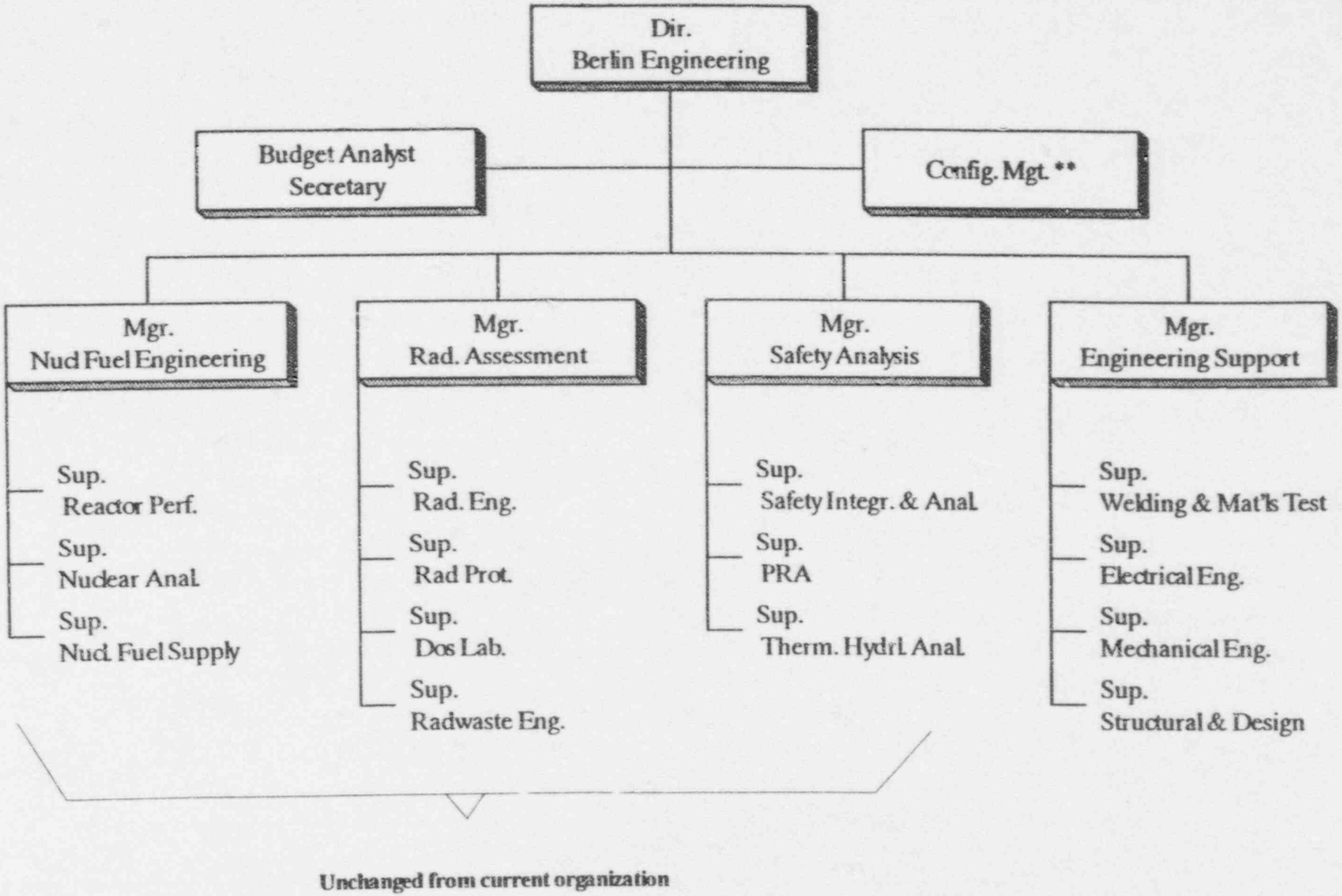
Civil, Structural, Mechanical, Electrical, I&C Engineering & Design and Drafting Support For All Unit and Site Design Change Activity.

Design Authority
Configuration Maintenance
App. R
EQ
HELB

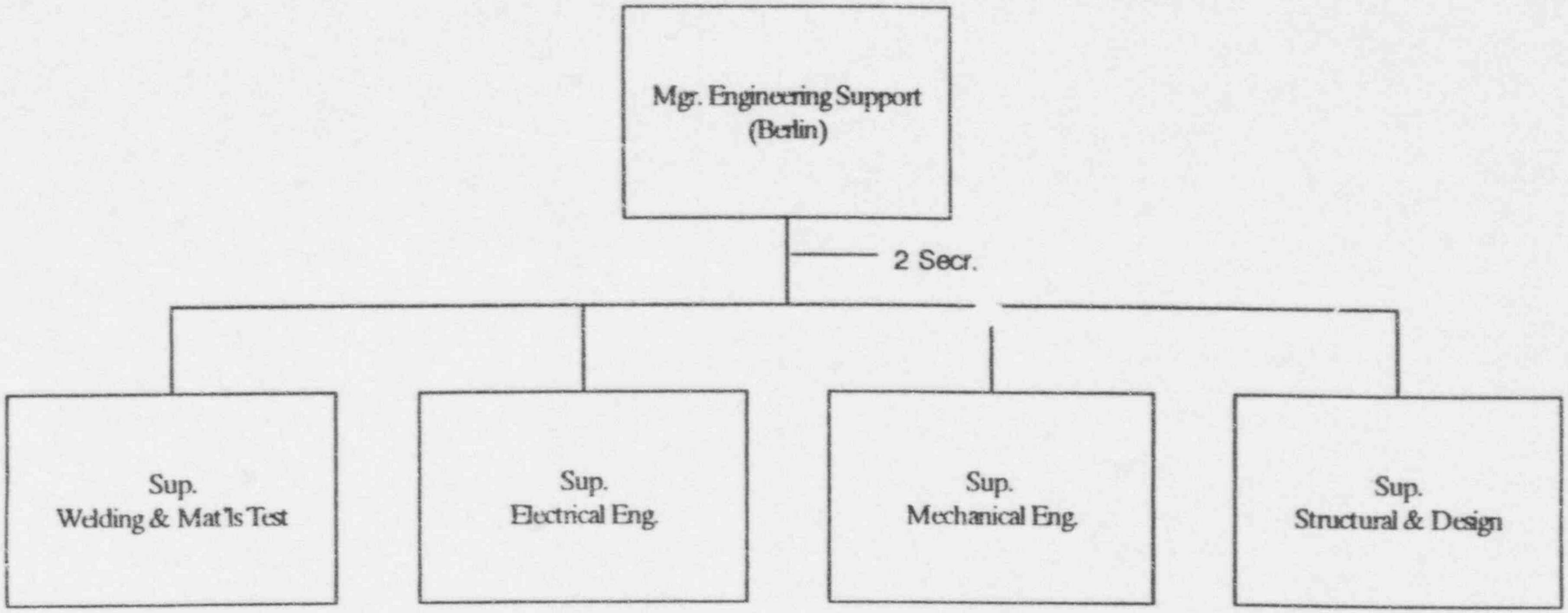
OPAL
SBO
Setpoint Change
MEPL
Design Change Progm.

Note: No. of Supervisors varies between units.

Berlin Engineering Organization



** Config. Mgt. PEP Action Plan scheduled for completion 2/95.



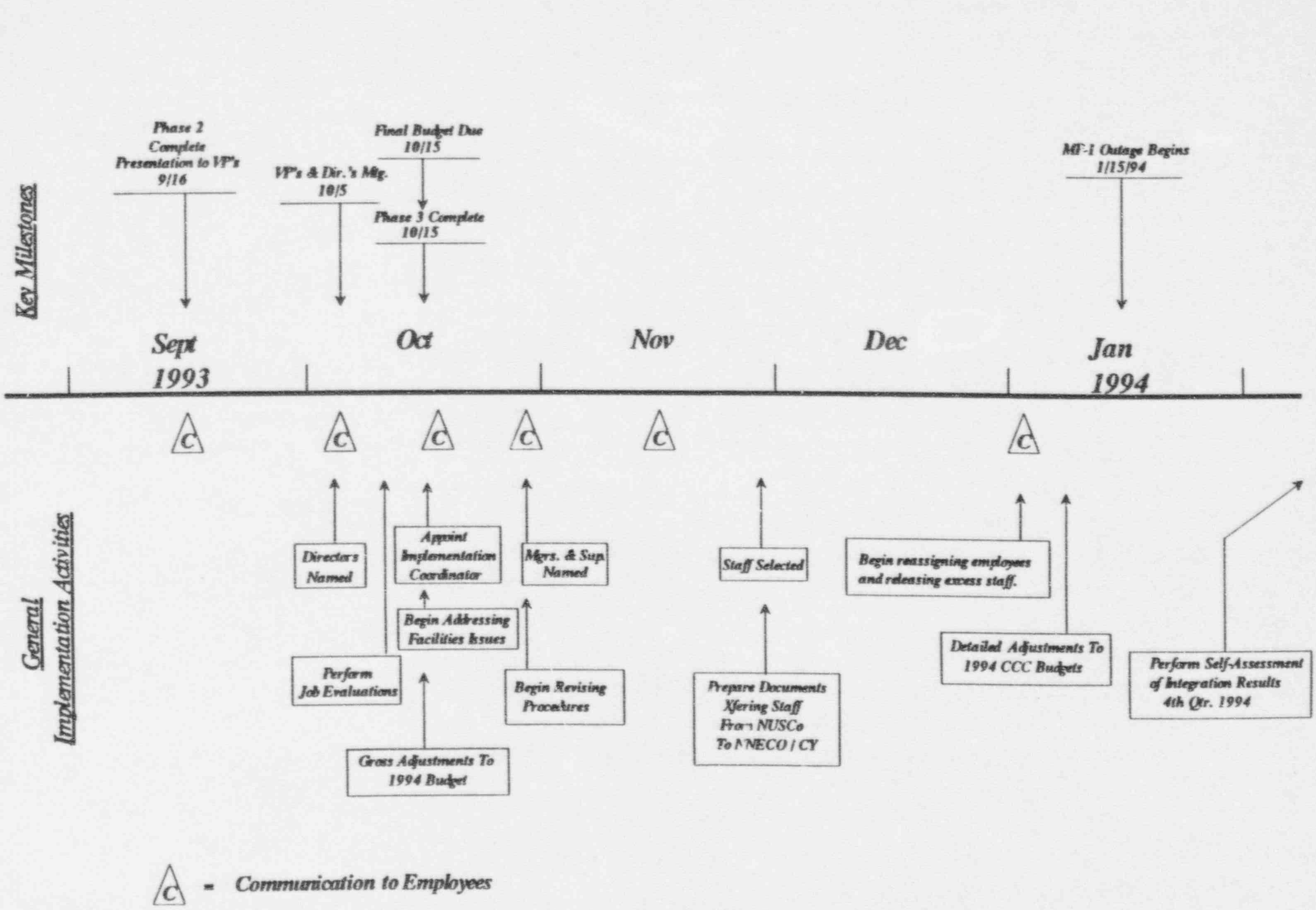
Welding
Materials
Failure Anal.
Turbines
ILRT
IGSCC
Sec XI
Clerk
Chemistry
S/G
- Inspect.
- Strategies

Motors
EEQ
Generators
Specialists
- ATWS
- SBO
- OPAL
- Setpoint Control
Clerk

Fire Prot.
E/C
MOV's
App. R
Ck. Valves
Serv. Water
Clerks
MEPL
HELB
Rx Surveil.
Fatigue Monitor.
HVAC

Civil
Stress
Seismic
Seismic USI A46
CAD
Design Control
Clerks

ENGINEERING INTEGRATION IMPLEMENTATION PLAN



EMPLOYEE CONCERNS

- O THIS SUBJECT WAS ADDRESSED ON PAGE 2 OF THE NOVEMBER 3, 1993 BRIEFING PACKAGE
- O THE ENCLOSED PAGES ARE NORTHEAST UTILITIES' PRESENTATION SLIDES

EMPLOYEE CONCERNS

NU Nuclear Safety Concerns Program

We are mindful of the need to maintain an atmosphere conducive to airing safety concerns. We continue to take actions to enhance that atmosphere.

- **An action plan in support of our Nuclear Goals has as its objective the fostering of a culture and work environment in which management encourages the raising and resolution of safety issues**
    - **The action plan is to be completed in 1994**
- **The PEP Action Plan dealing with the Employee Concerns Programs has been validated**
    - **Validation results: each of the Action Plan's intended effects were achieved**
    - **Validation team recommendations are being implemented**
- **Enhanced management training has been implemented**

EMPLOYEE CONCERNS (Cont.)

- A Self-assessment of the NSCP is planned
- The NSCP Director has been changed
  - 2-year rotational position
    - Minimizes perception of line management link
    - Brings a fresh perspective to the position

<u>10CFR 2.206 Petitions</u>

- Recent 10CFR2.206 petitions have alleged violations of 10CFR50.5 (Deliberate Misconduct) and 10CFR50.7 (Employee Protection)
  - The public nature of allegations of wrongdoing calls for timely petition resolution
  - We will respond proactively to such petitions to provide the Staff with information needed to act on the petitions

EMPLOYEE CONCERNS (Cont.)

- We encourage prompt Staff action, and would be pleased to further contribute to timely resolution

<u>Suggestions for the NRC Review Team</u>

- Share with licensees information regarding allegations brought directly to the NRC. This recommendation is safety driven
- Reemphasize to the Department of Labor the importance the Commission places on the prompt resolution of discrimination allegations
- Issue clearer and more explicit guidance regarding the preferred method of raising safety concerns: Bring them to the licensees' attention for resolution
- Provide licensees with the NRC's view of the desirable aspects of employee concerns programs.
- NRC investigations should be limited to instances where a pervasive pattern of discrimination may have developed

BUDGET

- O THIS SUBJECT WAS NOT ADDRESSED IN THE NOVEMBER 3, 1993, BRIEFING PACKAGE

- 0 THE FIRST EIGHT PAGES HEREIN ARE NORTHEAST UTILITIES' PRESENTATION SLIDES

- O THE LAST FOUR PAGES ARE FROM NORTHEAST UTILITIES' MONTHLY "MEASURES OF PERFORMANCE" DOCUMENT DATED SEPTEMBER 1993

BUDGET DATA

- Millstone and Haddam Neck Plant O&M Budgets for 1993 and forecasts for 1994 & 1995 have been revised downward, as originally intended, to reflect integration efficiencies

- Reductions are primarily the result of anticipated improvements in overall effectiveness of engineering organization
  - Process streamlining
  - Elimination of overlap, duplication, and complexity

- Specific reductions are to be achieved by not filling previously authorized positions and reducing contractor support

- Merger with Public Service of New Hampshire
  - Corporate resolve to apply all necessary resources to return Millstone to former level of operational excellence

BUDGET DATA (Cont.)

- Assurance that approach to Seabrook budgets will be motivated by same pursuit of operational excellence that characteristics Millstone and Haddam Neck budgets

- Commitments:

  - Complete Phase II of the PEP and docket results
  - Ensure that the PEP is acceptable to the NRR
  - Authorize additional of any resources necessary to implement the PEP
  - Provide periodic updates on the progress of PEP implementation
  - Keep the NRC Staff apprised of any significant changes in the O&M and capital budgets and projections for calendar years 1992-1995, including an explanation for any such changes

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CHAPTER I

EXECUTIVE SUMMARY

This 20-year forecast of loads and resources focuses on the needs of Northeast Utilities (NU) system retail and wholesale customers in New Hampshire, Connecticut, and Massachusetts and on how those needs are to be served by existing and planned programs and facilities.

Based on the Company's current projections, customers' needs can be met with existing demand and supply resources until 2007. This two-year extension in the Company's time of resource need as compared to last year's filing is due to two major factors:

- The Company's continued commitment to economic conservation and load management (C&LM) programs.
- A lower projection of regional growth due to the weakness in the current regional economy.

Since new resources are not projected to be needed for 14 years, the Company has no plans to solicit or build new resources at this time. Without a need for new resources the Company's goals are reducing the cost of energy, optimizing our existing resources including increasing energy efficiency through C&LM, and providing reliable electric service. These goals are discussed in Chapters I-V of this filing.

Organization of the Report

This report contains six chapters. This chapter, Chapter I, provides a summary of the entire report along with a description of NU's planning process, the need for new resources and resource options for the future.

Chapter II provides NU's forecast of peak loads, sales, and energy requirements through the year 2012. This chapter is summarized in section B below.

Chapter III discusses the planning, implementation, and evaluation of conservation and load management programs in NU's long term reference load forecast. This chapter is summarized in sections C and E below.

Chapter IV provides information on existing and planned generating resources through the year 2012. This chapter is summarized in sections C, D, and E below.

Chapter V provides data on existing and planned transmission facilities. This chapter is summarized in sections C and D below.

Chapter VI contains maps of the NU and New England transmission system.

A. NU's Integrated Resource Planning Process

NU makes its resource decisions based on its overall objective of being a financially sound, environmentally responsible, reliable and reasonably priced provider of electricity and related energy services. This is accomplished through an integrated resource planning process. In this process, the Company considers the demand options that either reduce or reshape the demand for electricity and the supply options available to meet that demand. It then seeks to identify the most suitable cost effective combination of resources, while considering the sensitivity to changes in key input variables and exploring appropriate actions to respond to probable contingencies.

The planning process at NU is not rigid or fixed. Rather, it is a continuously evolving, dynamic process which takes into account current and projected system circumstances. NU's planning process addresses both the long and short term. Over the long term, the integrated planning process considers supply-side and demand-side options and evaluates them as potential candidates in meeting future resource needs to provide an adequate, reliable and cost effective supply of electricity. In the short term, NU considers the cost of the current resource plan and the management of existing resources which may provide short-term benefits. Such items as fuel conversions, generating plant betterments, conservation and load management implementation considerations, energy and capacity sales and purchases, and unit retirements/deactivations are examples of current planning activities.

State and federal energy initiatives and implementing regulations have become an important resource planning consideration for NU. The Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992 are expected to significantly influence NU because of their broad scope. Nuclear plant licensing reform, fleet requirements for electric vehicles, renewable resource, SO_2 and NO_x control tax credits and, transmission policy, are addressed in these laws and will provide direction to the industry for years to come. Additionally, the national debate over energy taxes continues, a subject that could impact the cost of energy to our customers.

B. Load Growth Projections

Table I-1 shows the projected levels of summer and peak demand 10 and 20 years into the future and projected peak load and energy growth rates for selected periods. Winter peak demand for the Northeast Utilities system is forecasted to grow at an annual rate of about 1.6 percent over the period 1992-2012.

TABLE I-1

NORTHEAST UTILITIES SYSTEM
20-YEAR OUTLOOK FOR ENERGY & PEAK LOAD

Year	Energy (GWH)	Summer Peak (MW)	Year	Winter Peak (MW)
1992 (actuals)	33591	5781	1992/1993	6000*
2002	39218	7022	2002/2003	6986
2012	46237	8241	2012/2013	8255

*Estimated winter peak subject to change; unadjusted for losses

Forecast
Growth Rates

(Including impacts of C&LM)

Period	Energy	Summer Peak Load	Winter Peak Load
1992-2002	1.6%	2.0%	1.5%
2002-2012	1.7%	1.6%	1.7%
1992-2012	1.6%	1.8%	1.6%

A breakdown of the load forecast shows that over the next 10 years (1992/93 through 2002/03), the Company's winter peak load (without the effects of incremental demand management programs) is projected to grow at approximately 2.4 percent per annum. Inclusion of the incremental demand management options, currently part of the NU Resource Plan, reduces the peak growth to 1.5 percent per annum over the same 10 years.

During the same 10-year period, the Company's summer peak load (without the effects of incremental demand management programs) is projected to grow 2.8 percent per annum. Inclusion of the incremental demand management options reduces the growth to 2.0 percent per annum over the same 10 years.

These projections include, as in past years, the Company's explicit recognition of the threat of customer self-generation, as the utility industry continues to experience increased competition. Even with programs to manage our own costs, to increase the level and value of our service to customers, and to reduce the subsidies embedded in certain rates which give commercial and industrial customers an incentive to bypass the System, we have again included an estimated loss, which in 2002, amounts to some 410 GWh or about 1.1 percent of NU System sales at that time. This loss reflects the belief that certain customers have, and will exercise the option of obtaining their electricity requirements from sources other than NU.

C. Existing Resources and Transmission System

1. Existing Demand Side Resources

NU has been, and continues to be, a regional and national leader in the development and implementation of cost-effective and comprehensive demand side management programs. Over the past decade the Company's efforts in demand management programs have continued to evolve as new initiatives were developed and new electricity end use markets targeted. These past efforts have resulted in significant reductions to the Company's peak load. The effects of these past efforts, which are embedded in the Company's load forecast, are expected to continue into the future. At the end of 1992, the cumulative effects were estimated at 296 MW in summer and 214 MW in winter (see Table III-1).

2. Existing Supply-Side Resources

A major component of NU's Resource Plan is the MW (Net Unit Entitlements - Winter Rating) of utility-owned generating capacity, as detailed in Chapter IV. These resources, broken down by energy source, are as of January 1, 1993:

	Winter	Summer	Percent of Total
Nuclear	2960 MW	2917 MW	38
Fossil	3047 MW	2970 MW	39
Hydro	314 MW	309 MW	4
Pumped Storage	823 MW	822 MW	11
Cogeneration	636 MW	652 MW	8
TOTAL	7780 MW	7670 MW	100

The above capacity has been reduced by capacity sales and purchases. As most of the contracts terminate between 1993 and 1998, the bulk of that capacity will be available to the Company to meet the demand of its customers.

The Company's decision to retire five internal combustion units in 1992 reflects both the current surplus of capacity in New England and the continuing efforts by NU to lower its operating and maintenance costs. In an effort to reduce the near-term cost of energy, the Company is studying the deactivation of Montville Station for the period January 1995 through October 1998. While a final decision has not been made, this deactivation is included in this plan.

3. Existing Transmission System

A summary of the total mileage of the existing transmission system by operating company is included in Chapter V. The only changes from the previous year are the rebuilding of an existing 115 kV line from Newtown to Plumtree and the removal of several unenergized 69 kV lines.

D. Need for Expansion of the System

1. New Resource Needs

NU's resources are adequate to meet customer needs for the next 14 years, until 2007, at reference load growth assumptions. Figures I-1A and I-1B depict the combined NU system resources and resource requirements over the 20-year period 1993-2012 at the time of the summer and winter peak loads, respectively.

The states regulating NU subsidaries have integrated planning regulations to determine if a solicitation for new resources is necessary. Because NU's projected need for such additional resources isn't until 2007 (Figure I-1B), the Company does not anticipate making a solicitations for additional resources in the near term.

In light of the current economic downturn, increased focus on near-term electric rates and projected levels and duration of surplus capacity, the Company continues to reassess the projected pace of its C&LM program efforts and expenditures over the next several years. NU believes that the implementation rate of some programs can be moderated in the near term to reduce rate impacts without materially advancing the need for resources or impairing the effective long term development of the C&LM resource. These issues are the subject of ongoing discussion by the Company and the state commissions and the non-utility parties (NUPs) within the respective C&LM collaboratives.

Reasonable upper and lower bounds to any forecast of load growth should always be considered in resource planning. Assuming first a high load growth scenario in which loads grow at 2.4 percent per annum including the effects of C&LM, the Company's first year of capacity need would be 2002. The Company also examined a low growth scenario where loads grow at 0.8 percent per annum over the next 20 years. These scenarios are depicted for winter and summer peak periods in Figure I-2. Even under the high load growth scenario, there is more than ample time to evaluate resource options.

2. Near Term Siting Requirements for New Generating Facilities

Because of the Company's generating capacity surplus and the long lead time before any new resource need must be met, the Company does not need to commit to any future resources at this time. The Company envisions using cost effective demand side management resources to the extent possible to delay the need for additional supply-side resources, and, if need be, then considering repowering its older fossil-steam units at the existing generating stations, purchasing power from non-utility generators (NUGs), or appropriate new technologies.

3. Need for New Transmission Facilities/Upgrades

The tables in Chapter V detail the proposed transmission additions for the next 10 years. A discussion of the longer term needs is given in Section D of Chapter V.

E. Resource Options Available for the Future

1. Future Demand Side Management Options

Today's options for demand management include helping customers increase the efficiency with which they use electricity (for lighting, cooling, heating, and industrial processes) and shifting load from higher-cost, on-peak periods to lower-cost, off-peak periods in response to cost-based price signals.

NU's future demand side resources in its resource plan include a comprehensive mix of programs for residential, commercial and industrial customers. Certain C&LM programs are given first consideration in the resource plan. These are:

- Programs mandated by government in the interest of public policy,
- Programs in new construction (including replacement) which if not implemented, would result in significantly higher costs through retrofits at a later date, and
- Retrofit programs necessary to maintain an adequate infrastructure so that the C&LM resource can be effectively developed over the long term.
- Programs which promote economic development by assisting in the retention or attraction of business and industry to the area.

Beyond these core programs, the resource plan includes additional program activity designed to achieve cost effective efficiency improvements as well as to assure a broad distribution of program benefits to customers.

2. Future Supply Side Options

New supply options available to the Company include combined cycle, coal gasification and fluidized-bed coal technologies, combustion turbines, fuel cells and renewable resources. NU's future supply options are evaluated using a screening process. The results of the latest screening analysis indicate that the lowest cost new base and intermediate load option is a combined cycle unit fired by natural gas. That supply resource also serves as a proxy unit against which the Company's demand management programs are evaluated for determination of capacity savings.

Another option involves the purchase of power from new generating facilities built by others. NUGs, including Qualifying Facilities (QFs) and independent power producers (IPPs), offer a considerable choice of potential resource additions to meet the combined system's future resource requirements.

Additionally, periodic reviews of near term opportunities for conversion from oil to gas are performed in order to enhance NU's position as a least-cost, environmentally responsible provider of electricity. NU continues to pursue economic opportunities to enhance its fuel mix, to reduce environmental impacts and to reduce oil dependency and the accompanying risks of abrupt changes in oil prices and supply interruptions.

FIGURE I-1A
NU'S 20 YEAR RESOURCE PLAN
SUMMER 1993-2012

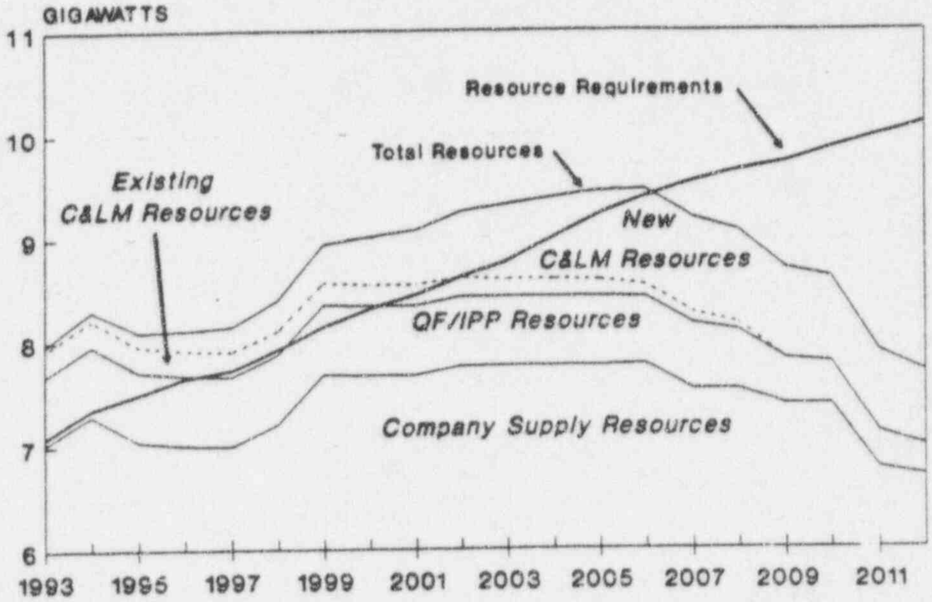


FIGURE I-1B
NU'S 20 YEAR RESOURCE PLAN
WINTER 1993-2012

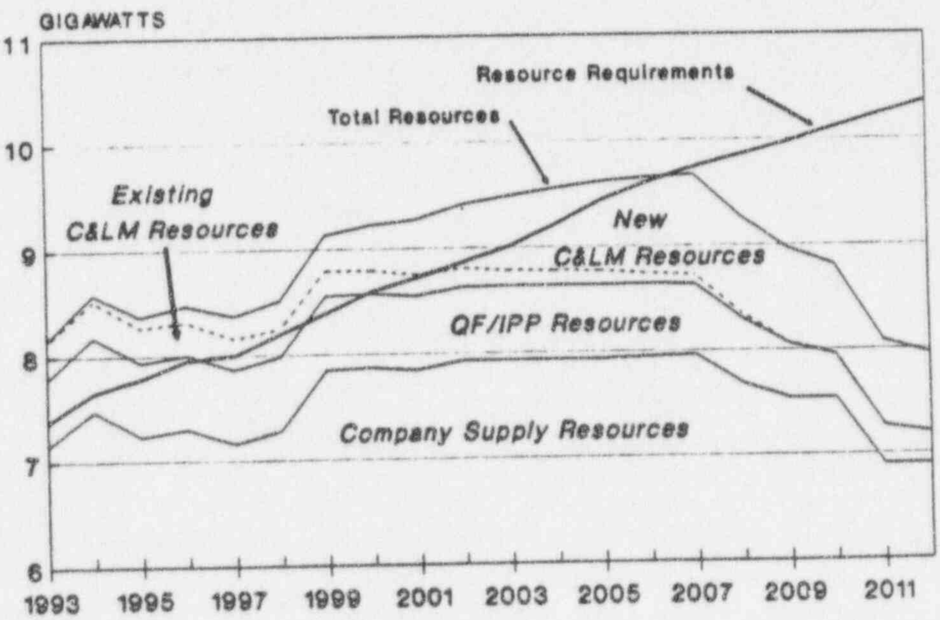
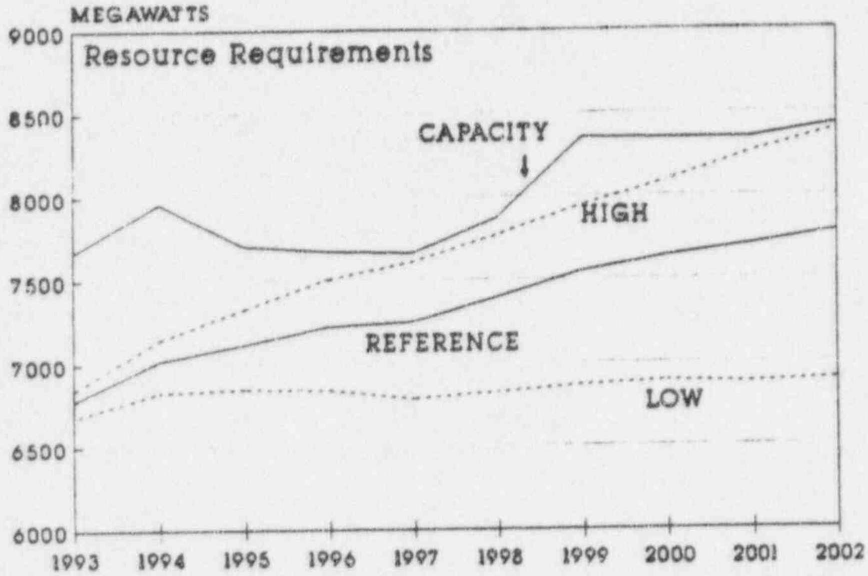
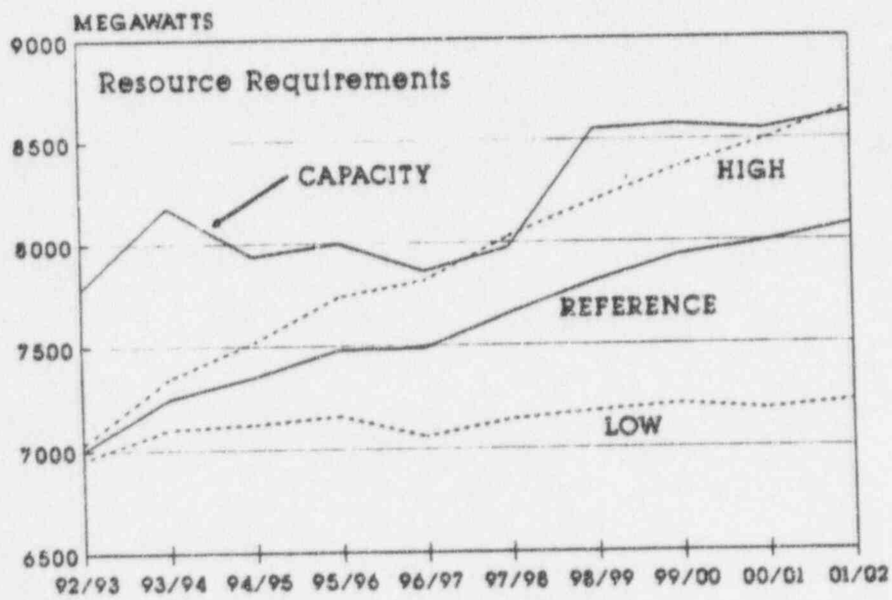


FIGURE I-2
SHORT TERM UNCERTAINTY IN REQUIRED RESOURCES

(SUMMER)



(WINTER)



CHAPTER II

ELECTRICAL ENERGY DEMAND FORECAST, 1993-2002

A. INTRODUCTION

The demand forecast, which provides input to the planning of future resources, focuses in part on the forecasted total annual consumption of electric energy. This is referred to as the energy forecast and it is expressed in terms of kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh). It is made up of forecasts of sales to customers, company use, and associated transmission, distribution, and transformation losses, which together make up the electrical energy requirements that must be supplied by generating plants to meet customer needs.

The forecast of the anticipated consumption of electrical energy is one guide for resource planning, but it does not include consideration of the expected maximum rate of use of electricity, termed demand, and measured in kilowatts (kW) or megawatts (MW). The facilities available to an electric utility system must be capable of generating, transmitting, and distributing electricity at that rate of use, otherwise loads must be cut back to prevent overloads and/or system failure.

The demand for electricity fluctuates from hour to hour, week to week, and season to season. Normally, the heaviest consumption in the winter occurs during daytime hours, rising to a peak generally in midmorning and again in the late afternoon or early evening. The heaviest consumption in the summer normally occurs between late morning and early evening, with 12-3 p.m. being the peak load period. The time when residential appliances, industrial machinery, commercial requirements for lighting and heating or cooling, and all other loads combine to produce the highest coincident hourly load of the year is the time of the annual peak for the system. Many factors can influence the timing and level of the peak load, including extreme weather, economic conditions and load management.

After the annual sales forecasts are developed for each customer class, corresponding hourly sales values are also developed. Estimated hourly company use and transmission, distribution, and transformation losses are subsequently added to forecasted hourly sales. The summation of hourly sales, company use and losses determines the forecast of hourly net electrical energy requirements. The highest hourly load in the year or season becomes the forecasted annual or seasonal peak demand.

The NU load forecast reflects the expectation that substantial improvements in the efficiency of electric use can and will occur over the forecast period.

Although resource planning is done for the Northeast Utilities operating companies as a single system and data in this chapter are presented on that basis, the forecast itself is derived from a summation of the forecasts of electric loads in the service areas of each of the four NU System operating companies.

The forecast is presented four ways:

- Trend Forecast - the results of the end-use models described in NU's "1993 Economic and Load Forecast For 1993-2002 and 2003-2012," unadjusted for 1) self-generation, including both committed projects that are scheduled to start up or come to full capacity in 1993 and unknown future projects, 2) NU economic development efforts including business retention, expansion and recruitment and 3) forecasted Company-sponsored demand-side management (DSM) programs.

- Baseline Forecast - the Trend Forecast minus sales losses due to self-generation.

- Economic Development Scenario - the Baseline Forecast adjusted for sales due to NU economic development efforts.

- Reference Plan - the Economic Development Scenario minus energy savings due to DSM programs. This is the official forecast filed in Connecticut.

B. THE SALES FORECAST

Table II-1 shows sales levels by type of customer for the historic period, 1970-1992, and for each year of the 1993-2002 forecast period. The 1993 forecast projects a compound annual growth rate in total sales of electrical energy of 1.4 percent between 1992 and 2002. In preparing a sales forecast, retail customers are divided into five classes: Residential, Commercial, Industrial, Streetlighting, and Railroad. In addition, NU's forecast includes its projection of "Wholesale Sales for Resale," which accounted for 4.3 percent of NU's total electric sales in 1992 and represents firm sales to municipal and private electric systems. "Bulk power sales" are excluded from "wholesale sales for resale" in this forecast. The sum of the retail and wholesale forecasts is the system sales forecast. Sales to the three major retail customer classes (Residential, Commercial, and Industrial) are forecast to increase at compound annual growth rates of 1.1, 2.2, and 1.3 percent, respectively, from 1992 to 2002. Over this same period, wholesale sales are projected to decrease at a compound annual rate of 4.2 percent, primarily due to the reclassification of Wallingford sales as bulk power sales. By 2002, sales to wholesale customers are forecast to represent 2.4 percent of NU's total electric sales.

C. SYSTEM ENERGY OUTPUT AND PEAK LOAD FORECAST

Table II-2 provides an overview of the historic output and summer and winter peaks for the 1970-1992 period, and forecast output and peaks for the 1992-2002 period. The historic combined system peaks were calculated by adding the initial NU system peaks and the PSNH peaks together because the data required to merge hourly loads and extract the true peak were not available and the frequency of coincidence is high. For the 18 months prior to merger (December 1990 to May 1992), combined system peaks were calculated on a more rigorous level by NU's Intercompany Arrangements Department. Historical peaks and output are not normalized for weather. Also, the 1987 through 1989 seasonal peak loads have been adjusted to reflect the effects of emergency measures (such as voltage reduction and interruptible contracts) that reduced peak demand. The forecasted peak demands do

not reflect any potential reductions caused by utility-initiated emergency load control measures. The table shows electrical energy output growing at a compound rate of 1.6 percent per year over the forecast period. Table II-2 also shows summer peak load growing at a compound rate of 2.0 percent and winter peak load increasing by 1.5 percent annually from 1992 to 2002.

Table II-3 presents actual and forecast sales, output and peak loads and compares this year's forecast with last year's forecast. For 1992, output was 0.7 percent below the 1991 level. For the year 2002, the output level in the current forecast is 2.7 percent below last year's forecasted level and the annual peak in 2002 is 4.8 percent below the level forecasted last year. As previously noted, forecasted output and peak load reflect projected impacts of DSM programs that are aimed at reducing NU system energy sales and peaks. They also reflect projected self-generation by NU's commercial and industrial customers, which displaces electricity that otherwise would be supplied by the NU system and increased load due to economic development. The Trend sales forecast, unadjusted for projected DSM and self-generation reductions and economic development, displays a more robust growth path of 2.2 percent compounded annually over the period 1992-2002 (see Table II-4). The unadjusted output and peak forecasts display comparable growth rates.

The self-generation load loss projections developed for the forecast reflect NU's analysis that certain customers within the commercial and industrial classes have sufficient incentive, in response to electric, gas and equipment prices, to adopt on-site electric generation technologies now available in many sizes and configurations. Customers may elect to generate some or all of their own electric needs, if their cost of purchasing electricity from NU exceeds the cost of generating that electricity. In most cases, natural gas is assumed to be the primary fuel at self-generation facilities. Rate structures, overall price level, fossil fuel prices, facility costs, and gas supply availability will be the primary determinants of the eventual magnitude of customer self-generation. In the first several years of the current forecast, it is assumed that NU will be able to offer flexible rates and DSM programs to these customers and therefore make it less attractive for them to self-generate.

The current analysis of NU's future position in a competitive environment indicates an incremental 50 MW load loss by 2002 and an incremental sales loss of approximately 410 GWhs due to the gradual penetration of self-generation beginning in the year 1993 for PSNH, 1997 for WMECO, and 2001 for CL&P. These totals include committed projects totaling 113 GWhs or 14 MW in 1993. (Losses from existing projects are already reflected in the Trend forecast.) Self-generation is forecasted to have a greater impact in the second ten years but the effect in the first ten years is assumed to be mitigated by marketing efforts. The consequences of these potential losses, along with current estimates of sales being displaced by Qualifying Facility self-generation projects, are incorporated into the load forecast.

The Company continues to monitor customer self-generation potential. A combination of field information and economic analysis yielded the level of self-generation reflected in the forecast. Actual self-generation losses could be greater or less than the forecasted losses depending on the economic factors that potential self-generators consider in their decision making process. However, the Company's cost containment efforts, rate design initiatives and customer service improvements,

including its conservation activities, are designed to make NU the preferred provider of electric energy services and, therefore, lessen potential self-generation losses.

Beginning in 1991 in CL&P and WMECO, NU initiated discounted electric rates to retain the load of businesses that might otherwise leave the NU service territory, generate a portion of their own electric needs, or fail. Also, NU, in cooperation with the Connecticut and Massachusetts economic development agencies, has offered discounted rates as part of a package of incentives to encourage employers to expand or to locate new facilities in the NU service territory. Recently PSNH has also been authorized to negotiate contracts for similar purposes in New Hampshire.

The models that were used to produce the Trend forecasts of energy output requirements and peak demands incorporate assumptions that reflect the price of electricity and fossil fuels, governmental regulations and standards, embedded technological change, and other factors that affect the consumption of electricity. The projected effects of Company-sponsored DSM programs (see Chapter III) and self-generation were then subtracted from the Trend forecast and the projected effects from economic development were added. Over the next ten years DSM programs are forecast to have significant impacts on the growth of sales and peak demands. Table II-4 presents the Trend forecast as well as the projected impacts of incremental DSM programs, self-generation and economic development.

As Table II-4 shows, retail sales in 1992 increased by 0.4 percent. The forecast reflects the expectation that economic conditions will improve during 1993. However, forecasted regional economic growth will be slower over the next ten years compared to the previous ten for a few basic reasons. While the maturation of the work force and the restructuring of the major economic engines (e.g., manufacturing and finance and insurance) will imply relatively low and stable unemployment rates, employment growth will be constrained by slowing population growth. As a consequence, growth in personal income and the production of goods and services will be slow. Therefore, the Trend forecast indicates slower electric sales growth in line with forecasted long-term trends in the growth of the regional and U.S. economies.

As Table II-4 demonstrates, DSM programs significantly reduce sales growth, causing the 1992-2002 compound growth rate to fall by 0.7 percentage points from 2.1 to 1.4 percent. The reductions vary by class. While the DSM programs have a relatively small impact on the residential class, reducing sales growth from 1.4 percent to 1.1 percent, they reduce the commercial class growth rate from 3.4 percent to 2.2 percent and the industrial class growth rate from 2.1 percent to 1.3 percent. Incremental self-generation primarily affects the industrial class, although minimally in the first ten years of the forecast.

From 1970 through 1992 the initial Northeast Utilities System's annual peak has occurred fifteen times in the winter and eight times in the summer. Seven of those summer peaks occurred in the last ten years. On a combined system basis, the annual peak has occurred in the winter from 1970-1989 and in the summer in 1990 and 1991. A winter peak occurring in January or February is recorded as the winter peak of the preceding calendar year. For example, the peak that occurred in February 1979, the peak of the 1978-1979 winter season, is listed as the winter

peak for 1978. The preliminary NU System 1992 annual peak is 6000 MW and occurred on Monday, February 1, 1993 from 6-7 p.m.

D. METHODOLOGY

The development of a sales forecast requires a service area forecast of economic and demographic conditions. Separate economic/demographic forecasts for the NU Connecticut, New Hampshire and Massachusetts service areas are based on Data Resources, Inc. (DRI) forecasts for the states of Connecticut, New Hampshire and the Commonwealth of Massachusetts and the Springfield and Pittsfield, Massachusetts Metropolitan Statistical Areas (MSA). Detailed descriptions of the NU economic/demographic forecasts and NU's forecast methodology are available in Chapters II and III of the NU report entitled, 1993 Economic and Load Forecast for 1993-2002 and 2003-2012. The sales forecast is developed by class by various end uses and incorporates assumptions to reflect customers' responses to price changes and conservation programs. Sales forecasts are disaggregated by end use to study detailed trends that affect energy consumption and to provide input to the hourly energy and peak load forecasts.

The peak load forecast is the maximum sum of the hourly forecasts of load for each customer class, company use and associated losses. The sum of the class hourly loads for each year, company use and associated losses is the annual forecast of system electrical energy requirements or output. This is the amount of energy which must be supplied by generating plants to serve the loads on the system.

Incorporation of Assumptions into Models and their Sources

The forecast is based on regional economic/demographic forecasts, a price of electricity forecast, and assumptions about numerous factors that affect electric usage. Assumptions used in the models are based on such sources as NU's DSM programs, NU's survey of appliance ownership (the "saturation survey"), load research by NU and other companies into customers' patterns of electricity use, federal and state mandated appliance efficiencies, appliance industry marketing data, construction standards, analyses made by NU staff of the effects of advanced insulation standards and size of dwellings on the use of energy for heating, judgments regarding the penetration of appliances into the residential market in future years, etc.

The forecast of hourly loads requires temperature data for each hour of the year. Hourly temperature data from Bradley Field, Windsor Locks, Connecticut were collected for the 42-year period, 1950-1991, to construct a weather year based on the National Oceanographic and Atmospheric Administration (N.O.A.A.) 30-year (1951-1980) normal weather data for Bradley Field. From the 42 years of monthly data, the weather year was constructed from actual months such that the weather year has a normal annual mean temperature and normal monthly mean temperatures, while also displaying typical weather patterns. This weather year was used for the initial NU companies. For PSNH the hourly temperatures in the NU weather year were adjusted for the difference between the monthly mean temperatures recorded by N.O.A.A. at Windsor Locks, Connecticut (Bradley Field) and Concord, New Hampshire for 1991.

Numerous assumptions, based primarily on load research data, are also used. These assumptions deal with the demand patterns of appliances and commercial and industrial hourly load profiles. Included with these assumptions are the effects of load control devices and rates on customer usage patterns. In total, the hourly load models contain thousands of specific assumptions regarding these factors.

The assumptions incorporated into the load forecasting models were reviewed by an NU staff group representing several areas of expertise including economics, engineering, consumer research, rate research, system planning, and energy utilization.

Role of Econometric and End-use Models

In the 1993 forecast, end-use models are used to forecast energy consumption. Economic analysis of the effects of economic drivers and the price of electricity on sales are used to supplement end-use assumptions. End-use models, such as the NU residential appliance model, are based on maxims which, if known with certainty, would yield perfect forecasts of consumption. The residential appliance model is based on the fact that residential sales equal the product of the number of appliances and the kilowatt-hour (kWh) usage of each of those appliances. Estimates about the number of appliances in use, use per appliance and hourly usage characteristics are developed based on survey, market research, and load test data. Long-run price effects, such as appliance efficiency improvements, are incorporated into the end-use model implicitly through decrements to appliance kWh usage. Short-run price effects are also included explicitly through the use of a price elasticity coefficient from an econometric analysis of NU residential sales.

An econometric model measures the historic relationships between a dependent variable to be forecasted (in the case of NU, the consumption of electricity) and causative factors which determine consumption such as price, number of customers, employment levels, or income. Econometric models estimate historic relationships which may or may not hold true for the future. For example, if some discrete change were to occur, such as a government mandate for more energy efficient building codes, an econometric forecast would tend to overestimate sales because the inherent assumption that historic trends will continue would only be partially true. Another limitation of econometric models is the inability to reflect certain types of detailed assumptions. For instance, an econometric model is unable to directly incorporate an assumption that water heaters shall have average thermostat settings of 120°F. The end-use models, by contrast, can accommodate such detail, and are useful in demonstrating the effects of policy changes. The NU forecast blends econometric and end-use models in order to incorporate the strengths of both methodologies.

Forecast of the Price of Electricity

Each forecast for the major retail classes contains a price-of-electricity term. Annual historic prices of electricity used in the model estimations are developed from rate schedules for each operating company and class of service. The forecast of electricity prices for the years 1993 and beyond is based on near-term revenue projections, trends in return on equity, and discussions with NU's Resource Planning Department. These annual escalation factors were applied to the 1992 price estimates by retail class to produce forecasted electricity prices. Prior to final analysis, all nominal

(current) electric price forecasts are adjusted to provide real (constant, inflation adjusted) prices.

Copies of the 1993 Economic and Load Forecast for 1993-2002 and 2003-2012 are available from the Economic and Load Forecasting Department, Northeast Utilities Service Company, P.O. Box 270, Hartford, Connecticut, 06141-0270.

E. ENERGY AND PEAK DEMAND LEVELS, 2003-2012

Forecasting peak demand two decades into the future is a highly speculative activity. The impact of new uses for electricity, new or alternative sources of energy supply, uncertainties about the effects of conservation measures and utility-supported economic development initiatives, price induced conservation, new technologies for both production and use of energy, and future levels of economic activity, all of which affect electricity consumption, are subject to major uncertainties. The 2003-2012 forecast is a continuation of the forecast for the 1993 to 2002 period. As a result, the 2003-2012 forecast assumes that the trends forecasted for the 1993 to 2002 period continue and significantly different future events which could affect electricity consumption do not occur.

The reference forecast for the 2003-2012 period draws upon a Data Resources, Inc., forecast which projects a slower rate of growth for the nation than was projected in last year's forecast. In this forecast, the economy of the NU service area is projected to lag somewhat behind the nation's because of a population growth rate that is expected to be slightly lower than the nation's.

Table II-5 shows the potential levels of energy output requirements and summer and winter peak demand for the 2002-2012 period. The ten year compound annual growth rates for 2002-2012 for output and summer and winter peak load are 1.7 percent, 1.6 percent and 1.7 percent, respectively.

TABLE II-1
NORTHEAST UTILITIES SYSTEM

SUMMATION OF SALES BY CLASS
HISTORY 1970 - 1992*
FORECAST 1993 - 2002
GIGAWATTHOURS

YEAR	RESI-DENTIAL	COMM-ERCIAL	INDUS-TRIAL	STREET LIGHTING	RAIL-ROAD	TOTAL RETAIL SALES	ANNUAL CHANGE (%)	WHOLE-SALE/ RESALE (*)	ANNUAL CHANGE (%)	TOTAL SALES (*)	ANNUAL CHANGE (%)
HISTORY											
1970	6674	4514	5511	174	0	16873		1924	-	18797	-
1971	7225	5010	5429	177	0	17842	5.7	2047	6.4	19889	5.8
1972	7870	5621	5783	208	0	19482	9.2	2241	9.5	21722	9.2
1973	8295	6176	6146	213	0	20830	6.9	2310	3.1	23139	6.5
1974	8352	5929	5869	211	0	20361	-2.3	2332	1.0	22693	-1.9
1975	8301	6200	5394	212	0	20107	-1.2	2295	-1.6	22402	-1.3
1976	8805	6486	5815	214	0	21320	6.0	2487	8.4	23807	6.3
1977	8938	6719	6014	220	0	21890	2.7	2615	5.1	24505	2.9
1978	9080	6958	6349	218	0	22606	3.3	2739	4.7	25344	3.4
1979	9241	7176	6657	218	0	23292	3.0	2801	2.3	26093	3.0
1980	9306	7343	6522	217	0	23388	0.4	2813	0.4	26202	0.4
1981	9241	7542	6546	209	1	23539	0.6	2638	-6.2	26177	-0.1
1982	9123	7705	6083	204	0	23117	-1.8	2076	-21.3	25193	-3.8
1983	9372	8112	6315	197	34	24031	4.0	2133	2.7	26164	3.9
1984	9721	8602	6739	197	87	25346	5.5	2230	4.5	27576	5.4
1985	9814	898[illegible]	6707	190	131	25823	1.9	2232	0.1	28055	1.7
1986	10405	9610	6830	184	148	27177	5.2	1929	-13.6	29106	3.7
1987	11084	10275	6934	179	123	28595	5.2	1269	-34.2	29864	2.6
1988	11800	10816	7094	179	126	30016	5.0	1208	-4.8	31224	4.6
1989	12031	11109	7123	176	134	30574	1.9	1354	12.1	31928	2.3
1990	11861	11347	6987	173	137	30507	-0.2	1241	-8.3	31748	-0.6
1991	11823	11179	6686	172	137	29997	-1.7	1405	13.2	31402	-1.1
1992	11956	11201	6643	171	142	30112	0.4	1346	-4.2	31458	0.2
COMPOUND RATES OF GROWTH (%) 1970 - 1992	2.7	4.2	0.9	-0.1		2.7		-1.6		2.4	
FORECAST											
1993	12200	11368	6630	171	145	30514	1.3	886	-34.2	31400	-0.2
1994	12366	11621	6729	168	147	31031	1.7	914	3.2	31945	1.7
1995	12466	11944	6736	169	147	31462	1.4	954	4.4	32416	1.5
1996	12678	12374	6962	170	216	32400	3.0	973	2.0	33373	3.0
1997	12792	12663	7104	170	215	32944	1.7	992	2.0	33936	1.7
1998	12938	12975	7282	170	215	33580	1.9	993	0.1	34573	1.9
1999	13052	13271	7413	173	215	34124	1.6	1011	1.8	35135	1.6
2000	13192	13526	7511	174	216	34619	1.5	935	-7.5	35554	1.2
2001	13258	13693	7524	175	215	34865	0.7	859	-8.1	35724	0.5
2002	13338	13913	7546	176	215	35188	0.9	87[illegible]	[illegible]	36064	1.0
COMPOUND RATES OF GROWTH (%) 1992 - 2002	1.1	2.2	1.3	0.3		1.6		-4.2		1.4	

* HISTORY HAS BEEN RESTATED TO INCORPORATE PSNH DATA.

TABLE II-2
NORTHEAST UTILITIES SYSTEM

NET ELECTRICAL ENERGY OUTPUT REQUIREMENTS AND PEAK LOADS
HISTORY 1970 - 1992
FORECAST 1993 - 2002

	NET ELECTRICAL ENERGY OUTPUT REQUIREMENTS (1)		SUMMER (4)			WINTER (4)		
YEAR	OUTPUT	ANNUAL CHANGE	PEAK	ANNUAL CHANGE	LOAD FACTOR	PEAK	ANNUAL CHANGE	LOAD FACTOR
	GWH	(%)	MW	(%)	(2)	MW	(%)	(2)
HISTORY (5)								
1970	20640	-	3384	-	0.696	3899*	-	0.604
1971	21693	5.1	3614	6.8	0.685	4096*	5.1	0.605
1972	23725	9.4	3858	6.8	0.700	4567*	11.5	0.591
1973	25028	5.5	4348	12.7	0.657	4426*	-3.1	0.646
1974	24605	-1.7	4035	-7.2	0.696	4371*	-1.2	0.643
1975	24450	-0.6	4190	3.8	0.666	4704*	7.6	0.593
1976	26003	6.4	4271	1.9	0.693	4957*	5.4	0.597
1977	26471	1.8	4679	9.6	0.646	5004*	0.9	0.604
1978	27[illegible]74	4.2	4796	2.5	0.656	5124*	2.4	0.614
1979	28109	1.9	4746	-1.0	0.676	5114*	-0.2	0.627
1980	28550	1.6	5013	5.6	0.648	5327*	4.2	0.610
1981	28112	-1.5	4916	-2.0	0.653	5223*	-1.9	0.614
1982	27224	-3.2	5005	1.8	0.621	5124*	-1.9	0.606
1983	28413	4.4	5051	0.9	0.642	5147*	0.4	0.630
1984	29779	4.8	5248	3.9	0.646	5618*	9.2	0.603
1985	30406	2.1	5464	4.1	0.635	5622*	0.1	0.617
1986	31631	4.0	5357	-1.9	0.674	5546*	-1.3	0.651
1987	32459	2.6	5708	6.5	0.649	6136*	1[illegible]	0.604
1988	34123	5.1	6085	6.6	0.638	6261*	2.0	0.620
1989	34847	2.1	6023	-1.0	0.660	6194*	-1.1	0.642
1990	34139	-2.0	5943*	-1.3	0.656	5939	-4.1	0.656
1991	33829	-0.9	6143*	3.4	0.629	6024	1.4	0.641
1992 (3)	33591	-0.7	5781	-5.9	0.661	6000*	-0.4	0.637
COMPOUND RATES OF GROWTH (%) 1970-1992								
	2.2		2.5			2.0		
FORECAST								
1993	34139	1.6	6069	5.0	0.642	6189*	3.1	0.630
1994	34752	1.8	6197	2.1	0.640	6296*	1.7	0.630
1995	35341	1.7	6304	1.7	0.640	6431*	2.1	0.627
1996	36273	2.6	6453	2.4	0.640	6541*	1.7	0.631
1997	36870	1.6	6594	2.2	0.638	6658*	1.8	0.632
1998	37569	1.9	6717	1.9	0.638	6767*	1.6	0.634
1999	38176	1.6	6831	1.7	0.638	6839*	1.1	0.637
2000	38647	1.2	6885*	0.8	0.639	6871	0.5	0.640
2001	38839	0.5	6959*	1.1	0.637	6920	0.7	0.641
2002	39218	1.0	7022*	0.9	0.638	6986	1.0	0.641
COMPOUND RATES OF GROWTH (%) 1992-2002								
	1.6		2.0			1.5		

1. SALES PLUS LOSSES AND COMPANY USE.
2. ALL LOAD FACTORS AND ANNUAL PERCENT CHANGES ARE CALCULATED USING ACTUAL DATA (NOT NORMALIZED). IN PARTICULAR, THE LOAD FACTOR = (OUTPUT (MWH)) / (8760 HOURS X SEASON PEAK (MW)).
3. THE 1992 WINTER PEAK IS PRELIMINARY.
4. SUMMER AND WINTER PEAKS FROM 1970 THROUGH 1981 INCLUDE CMEEC LOAD
5. HISTORICAL DATA HAVE BEEN RESTATED TO REFLECT CONSOLIDATED NU SYSTEM AND PSNH ENERGY OUTPUT AND PEAK LOADS.

TABLE II-3
NORTHEAST UTILITIES SYSTEM

PRINCIPAL FORECAST RESULTS AND
COMPARISON OF CURRENT AND PREVIOUS FORECASTS

	ACTUAL*			FORECAST (FOR YEAR 2002)			COMPOUND RATES OF GROWTH **	
	1991	1992	PERCENT DIFF.	1992 FORECAST	1993 FORECAST	PERCENT DIFF.	(91-02)	(92-02)
	(1)	(2)	(2)/(1)	(3)	(4)	(4)/(3)	(5)	(6)
SALES (GWh)								
RESIDENTIAL	11823	11956	1.1%	13266	13338	0.5%	1.1%	1.1%
COMMERCIAL	11179	11201	0.2%	13733	13913	1.3%	1.9%	2.2%
INDUSTRIAL	6686	6643	-0.6%	8308	7546	-9.2%	2.0%	1.3%
STREET LIGHTING	172	171	-0.6%	204	176	-13.9%	1.6%	0.3%
RAILROAD	137	142	3.1%	142	215	51.4%	0.3%	4.3%
RETAIL	29997	30112	0.4%	35654	35188	-1.3%	1.6%	1.6%
WHOLESALE	1405	1346	-4.2%	1573	876	-44.3%	1.0%	-4.2%
TOTAL	31402	31458	0.2%	37226	36064	-3.1%	1.6%	1.4%
OUTPUT AND PEAKS								
OUTPUT (GWh)	33829	33591	-0.7%	40289	39218	-2.7%	1.6%	1.6%
SUMMER PEAK (MW)	6143	5781	-5.9%	7347	7022	-4.4%	1.6%	2.0%
*** WINTER PEAK (MW)	6024	6000	-0.4%	7373	6986	-5.2%	1.9%	1.5%

* - History has been restated to incorporate PSNH data.

** - Column (5) growth rates are actual 1991 to the 1992 forecast of 2002 sales and column (6) are actual 1992 to the 1993 forecast of 2002 sales.

*** - The 1992 winter peak is preliminary.

TABLE II-4
NORTHEAST UTILITIES SYSTEM

1993 LONG-RUN REFERENCE PLAN
(GWH)

	1992 ACTUAL*	1993 FORECAST	2002 TREND FORECAST	2002 BASELINE (TREND ADJ FOR SELF-GEN)	2002 ECON DEV SCENARIO (TREND ADJ FOR SELF-GEN & ECON DEV	2002 REFERENCE (TREND ADJ FOR SELF-GEN ECON DEV AND DSM
RESIDENTIAL SALES	11956	12200	13794	13794	13794	13338
% CHG	1.1	2.0				
COMPOUND RATE OF GROWTH			1.4	1.4	1.4	1.1
COMMERCIAL SALES	11201	11368	15751	15648	15671	13913
% CHG	0.2	1.5				
COMPOUND RATE OF GROWTH			3.5	3.4	3.4	2.2
INDUSTRIAL SALES	6643	6630	8163	7856	8174	7546
% CHG	-0.6	-0.2				
COMPOUND RATE OF GROWTH			2.1	1.7	2.1	1.3
STREETLIGHTING SALES	171	171	182	182	182	176
% CHG	-0.6	0.0				
COMPOUND RATE OF GROWTH			0.6	0.6	0.6	0.3
RAILROAD SALES	142	145	215	215	215	215
% CHG	3.1	2.4				
COMPOUND RATE OF GROWTH			4.3	4.3	4.3	4.3
TOTAL RETAIL SALES	30112	30514	38105	37695	38036	35188
% CHG	0.4	1.3				
COMPOUND RATE OF GROWTH			2.4	2.3	2.4	1.6
WHOLESALE SALES	1346	886	876	876	876	876
% CHG	-4.2	-34.2				
COMPOUND RATE OF GROWTH			-4.2	-4.2	-4.2	-4.2
TOTAL SALES	31458	31400	38982	38572	38913	36064
% CHG	0.2	-0.2				
COMPOUND RATE OF GROWTH			2.2	2.1	2.1	1.4
PEAK DEMAND **	6000	6189	7598	7548	7605	7022
% CHG	-2.3	3.2				
COMPOUND RATE OF GROWTH			2.4	2.3	2.4	1.6

* HISTORICAL DATA HAVE BEEN RESTATED TO INCORPORATE PSNH DATA.
** 1992 PEAK IS PRELIMINARY.

TABLE II-5
NORTHEAST UTILITIES SYSTEM

NET ELECTRICAL ENERGY OUTPUT REQUIREMENTS AND PEAK LOADS
FORECAST 2002 - 2012

YEAR	NET ELECTRICAL ENERGY OUTPUT REQUIREMENTS (1)		SUMMER (4)			WINTER (4)		
	OUTPUT	ANNUAL CHANGE	PEAK	ANNUAL CHANGE	LOAD FACTOR	PEAK	ANNUAL CHANGE	LOAD FACTOR
	GWH	(%)	MW	(%)	(2)	MW	(%)	(2)
2002	39218	1.0	7022*	0.9	0.638	6986	1.0	0.641
2003	39646	1.1	7099*	1.1	0.638	7064	1.1	0.641
2004	40240	1.5	7202*	1.5	0.636	7154	1.3	0.640
2005	406[illegible]3	0.9	7279*	1.1	0.637	7232	1.1	0.641
2006	41064	1.1	7358	1.1	0.637	7378*	2.0	0.635
2007	41922	2.1	7498	1.9	0.638	7533*	2.1	0.635
2008	42902	2.3	7639	1.9	0.639	7682*	2.0	0.636
2009	43611	1.7	7792	2.0	0.639	7833*	2.0	0.636
2010	44444	1.9	7948	2.0	0.638	7967*	1.7	0.637
2011	45262	1.8	8092	1.8	0.639	8118*	1.9	0.636
2012	46237	2.2	8241	1.8	0.639	8255*	1.7	0.638
COMPOUND RATES OF GROWTH (%) 2002-2012	1.7		1.6			1.7		

* DENOTES COMPANY PEAK

CHAPTER IV

EXISTING AND PLANNED SUPPLY RESOURCES 1993-2012

A. Introduction

NU's existing and planned supply resources comprise a diversified mix of generating units that are anticipated to be adequate to meet demand over the next 15 years. These resources provide environmentally sound and reliable energy for its customers. Since NU's year of capacity need is 2007, no supply resources beyond an additional 68 MW of NUG capacity are planned at this time. During 1992, Silver Lake Units 10-13 and Tracy (89 MW) were retired.

B. Explanation of Tables

The capacity tables in this chapter display estimates of NU's supply resources during the 1993-2012 forecast period. All generating units are given winter and summer ratings in megawatts to reflect the effects of varying ambient air and water temperatures on thermal units' ratings and river flow conditions on hydro units' ratings. Throughout this chapter, winter ratings are used in assessing NU's capacity situation relative to the forecast winter peak demand, and summer ratings are used in assessing its capacity situation relative to the forecast summer peak demand.

The forecasts of winter and summer peak demands used in this chapter are consistent with those presented in Chapter II, Tables II-2, II-3, and II-4. That demand forecast reflects NU's most recent assessment of customer conservation and load management potential, the potential losses due to customer self-generation and the increase in demand resulting from the Company's marketing efforts. Not reflected in the demand forecast are direct load control devices and interruptible service contracts which, if called upon during New England Power Pool (NEPOOL) demand emergencies, would further reduce peak demand. These measures contribute to reducing the system's capability responsibility as required by NEPOOL, and thus lower overall resource needs. (The reader is referred to Chapters II and III for additional details.)

Net capacity available to serve load is developed from:

- the existing wholly-owned generating units detailed in Table IV-1;
- NU's current share of the capability of other units and capacity purchases, sales and exchange contracts with other companies, as detailed in Table IV-2;
- generation additions shown in Table IV-3; and
- retirement of generating units shown in Table IV-4.

With respect to capacity purchases, sales, and exchanges with other utilities, the amounts shown on the tables reflect executed contracts or letters of understanding and contracts under negotiation which have a reasonable likelihood of being executed in the near future. Contracts to purchase, sell, and exchange capacity and

energy are reviewed on an ongoing basis and are entered into only if they will lower customers' costs and risks.

Table IV-5 shows that no generation additions are forecasted at this time.

Table IV-6 summarizes the twenty-year load and capacity situation for the NU system during the winter and summer peak periods of 1993 through 2012. The table also shows the system's reserve expressed in megawatts and as a percent of peak load. Not shown on the table are commitments to the Hydro-Quebec Phases I and II contracts, interruptible load contracts, and load control measures. These elements of the resource plan contribute to reducing NU's Capability Responsibility to NEPOOL.

Table IV-7 provides details on the capacity and energy contribution from existing cogeneration and small power production facilities 1 MW and greater.

C. Energy Supply

The table below shows the extent to which the system has been able to reduce its reliance on oil by comparing the 1973 (pre-oil embargo) energy contribution by source with 1980 and 1992.

In 1980 NU's energy resources consisted of a mix of nuclear, oil, and hydroelectric energy. By 1992, the energy mix had become less oil dependent and included coal, natural gas, and power from non-utility generation. NU has diversified its energy resources and has reduced oil dependence over the long term.

ENERGY CONTRIBUTION BY SOURCE
(Percent)

	1973	1980	1992*
Hydro	5	3	5
Nuclear	19	50	48
Coal	1	0	11
Gas	1	0	3
Oil	74	47	25
Non-Utility Sources	-	-	8
TOTAL	100	100	100
Energy Requirements (GWh)	19,600	21,679	30,204**
Oil Dependence (millions of barrels)	28.0	18.6	12.9

*Contribution from initial NU system in first half of 1992 and combined system for second half of 1992.

**Includes non-utility generation.

During 1992, the nuclear plants operated at an aggregate capacity factor of approximately 60 percent and, along with purchased nuclear energy, contributed about 48 percent of the NU system's total energy requirements, thereby reducing NU's

system oil dependence by nearly 27 million barrels from what it could have been in the absence of nuclear power. The 1992 nuclear capacity factor is considered an aberration. Capacity factors are expected to improve as NU implements a nuclear performance enhancement program.

D. Supply Resources for 1993-2012

The planned supply resources for the 1993-2012 forecast period include:

- hydro units and most of the existing fossil-fired units;
- non-utility generation under contract and with NHPUC orders;
- capability credit associated with the NEPOOL purchase of firm energy over the Hydro-Quebec interconnection;
- all existing nuclear units until license expiration; and
- purchases, sales, and exchanges of capacity and energy with other utilities to lower customers' costs.

Screening studies done by the Company indicate the most likely options are as follows:

- repowering of some older oil-fired units as natural-gas fired combined-cycle generating units,
- installation of new, more efficient peaking gas turbine generating units, and
- minor additions of capacity at existing hydro sites.

Additionally, because of the short lead times (4-7 years) required to develop these options and the ease with which they can be located at existing sites, they can be considered good supply candidates in the event contingency decisions must be made. Such contingencies might arise as a result of load growth being higher than forecast, or lower than anticipated demand reductions from planned demand side management measures.

Continued Operation of Existing Fossil-Fired and Hydro Units

Given the difficulty in siting new generation and transmission facilities, NU believes it is sound policy to preserve existing generating sites and resources, rather than to dispose of them and later have to develop new ones. Most existing fossil-fired and hydro resources provide an economic and reliable source of generation. Accordingly, NU will continue to maintain these sites in a manner that will preserve their long-term usefulness and availability as long as they are economic. Several units are forecast to be either retired or deactivated, and these are shown on Table IV-4. In order to reduce costs to customers in the short term, NU is studying the deactivation of Montville Station for the period January 1995 through October 1998. While a final decision has not been made, this deactivation is included in this plan.

Non-Utility Generation

With the recent addition of Public Service of New Hampshire to the Northeast Utilities family, there are 54 NUGs of 1 MW or greater in size that sold power to NU during 1992.

Of these 54 facilities, 45 NUGs with a capacity of approximately 643 MW sell power to NU under long-term contracts or rate orders. Currently, the total capability for NUGs interconnected to the NU system is 636 MW (Winter) and 598 MW (Summer).

The remaining 9 NUGs do not operate under long-term contracts or rate orders but rather sold energy to NU at non-firm energy rates. Therefore, under NEPOOL rules these facilities do not provide capability credit to the NU system.

By 1995, with the planned contractual additions of Rimmon Pond (1 MW), MassPower (54 MW) and Lisbon (13.5 MW), NU estimates that the resulting 48 NUGs operating under long-term agreements or rate orders will have an associated capacity of 712 MW. NU anticipates a resulting 1995 capacity rating of 703 MW (Winter) and 666 MW (Summer) from these NUG capacity commitments to its electric system.

It should be noted that this estimate of the 1995 capability rating is a reduction to the 764 MW (Winter) and 751 MW (Summer) estimated in last year's report. This reduction is due mainly to the termination of purchase agreements with Bio-Gen (13 MW), ARS (32.2 MW) and Brockton Wood (Tamal) (16.9 MW). The Connecticut Legislature required the DPUC to order the buy-out of the Bio-Gen and ARS Electricity Purchase Agreements by CL&P. In addition, in November 1992, the Massachusetts DPU disapproved the Electricity Purchase Agreement for the Brockton Wood project.

On February 8, 1993, NU issued a "Reverse Request for Proposal" (RRFP) for consideration by non-utility generators. Its purpose is to solicit proposals to reduce the anticipated ratepayer impacts from NUGs, with emphasis on the next 6 years.

Hydro-Quebec Interconnection

The New England portion of Hydro-Quebec Phases I and II facilities entered commercial operation on October 1, 1986, and November 1, 1990, respectively.

For capability responsibility purposes, the benefits from Hydro-Quebec interconnection and associated contracts are converted into equivalent capacity values during the firm energy contract period. NU's share of these equivalent capacity values are 166 MW in winter and 246 MW in summer for Phase I and 239 MW in winter and 354 MW in summer for Phase II. This aggregates to 406 MW in winter and 601 MW in summer. The Phase II contract currently extends to the year 2000 with an extension period through 2004 to receive undelivered energy. If no new contract takes its place, the interconnection will still provide tie benefits. In light of this, NU assumes that its Hydro-Quebec capability credit will be reduced to 70% of its current value beginning in the fall of 2004.

Purchases and Sales of Bulk Power

NU has long recognized that energy purchases and sales are an important way of minimizing electricity costs and improving generation mix. For example, NU's energy purchase arrangements have helped to substantially reduce the overall cost of serving customer load. Power purchases include buying power from other New England utilities as well as from utilities in New York State and in the Pennsylvania-Jersey-Maryland (PJM) interconnection. NU's contracts with utilities outside of New England provide a means to improve the availability of economy energy to NEPOOL and to reduce NU's energy costs. The Northfield Mountain Pumped Storage Facility plays an important role in NU's ability to make energy purchases and sales. NU can buy relatively inexpensive power during the off-peak periods and store it at Northfield by pumping water into an upper pond. This stored energy is used during peak periods, thereby reducing NU's cost of peak period generation and providing more opportunities to make energy sales. NU purchased about 2.1 million MWh of economic energy during 1992, and NU sold approximately 0.3 million MWh of energy for economy purposes to others during 1992.

Likewise, NU's contracts for sales of surplus capacity and associated energy to other utilities have helped to significantly reduce the overall revenue requirements from NU's customers. In 1992 NU's wholesale marketing efforts resulted in the sale of an additional 1,000 MW-years of surplus capacity. The level of future NU capacity purchases and sales will depend on the bulk power market in New England and adjacent regions, on external influences such as regulatory policies and decisions, and on the NU system's capacity situation.

The capacity market in New England is expected to continue to be very competitive in the next few years. This is a result of the regional economic downturn and resultant lowering of load growth projections, along with aggressive DSM program implementation by many utilities, and several recent capacity additions in New England including Seabrook, Hydro-Quebec Phase II, and various NUGs. However, NU will continue to attempt to sell its available capacity at rates which at least recover the marginal costs of such capacity.

Hydro Capacity

NU has no plans to install additional hydro capacity during this planning horizon.

WMECO's FERC license for the Gardners Falls hydroelectric project in Buckland, and Shelburne, MA, expires at the end of 1993. An application for a new license, filed by WMECO on 12/23/91, is currently under FERC review. Public Service Company of New Hampshire's FERC licenses for the Ayers Island, Gorham, and J. Brodie Smith hydroelectric projects in New Hampshire will expire on 12/31/93. Applications for new licenses, filed by PSNH in December 1991, are currently undergoing FERC review. With the exception of environmental and recreational enhancement measures, PSNH is not proposing any physical or operational changes to these facilities.

On August 11, 1992, the FERC issued orders granting exemptions from licensing for the Company's four hydroelectric projects on the Chicopee River: Red Bridge, Putts Bridge, Indian Orchard, and Dwight. The Company is in the process of developing a

plan to implement the environmental and recreational enhancements included with the FERC exemption orders.

Fuel Mix Diversification

Conversion of existing oil-fired units to multiple fuel-firing capability does not add any resources to overall system capacity; its potential value lies in further reducing oil dependence as well as reduced emissions, thereby helping to assure service reliability, while reducing costs to customers. NU continues to study the technical and economic feasibility of providing its oil-fired units with interruptible natural gas firing capability. NU converted its Newington Station (406 MW) to dual fuel capability (oil/gas) during 1992 and continues to study the conversion of Devon Units 7 and 8 to burn interruptible natural gas.

E. Long-Term Planning Issues

Planning supply options for the longer term, i.e., post-2000, requires considering a number of relevant issues. Some of them are briefly discussed here. They include environmental issues, uncertainty of resource need, availability and price of fuels, progress on developing new technologies, using existing sites and relicensing of existing nuclear plants.

Environmental Issues

The pursuit of "least cost" plans has become a more complex activity in recent years as environmental matters have moved to the forefront. Because future environmental regulations and their associated costs are uncertain, planners must allow for unknown factors in postulating what is "least cost." Today there are several key environmental issues that are important to consider in resource planning: the new acid rain regulations, NO_x compliance, and other CAAA issues (air toxics, fleet vehicles). These issues are related to provisions of the Clean Air Act and the 1990 Amendments. Most important are the regulation of SO_2 and NO_x for the purpose of controlling acid rain (Title IV), attainment of Ambient Air Quality Standards, most notably ozone (Title I) and other issues such as monitoring and air toxics control.

The following summarizes where the Company stands on the major areas of compliance with the 1990 Clean Air Act Amendments and its implementing regulations, as well as the Massachusetts and New Hampshire Acid Rain Laws compliance efforts. The two principal areas of CAAA compliance are NO_x and SO_2 emissions reductions.

The principal impacts of the CAAA on NU consist of some modest SO_2 reductions from the acid rain portion of the law (Title IV), and NO_x reductions at all of our fossil steam units from the non-attainment portion (Title I).

Acid Rain

Phase I

The first major compliance activity for the acid rain portion of the CAAA was the filing of Title IV permit applications by February 15, 1993 with EPA Region I for our Phase I units. The only two designated Phase I units on the NU system (and in New England) are Merrimack 1 and 2. Beginning in 1995,

these units will be granted allowances by EPA and the units' emissions will be subject to Title IV regulation. An allowance is the right to emit one ton of SO_2.

In its Phase I Application the Company also included Newington and Mount Tom as conditional substitution units to provide an additional margin for compliance with Phase I. These substitution units, if needed, will also be granted allowances based on historical performance. Continuous emissions monitors (CEMs) will be installed at these four units. The Company is planning to use the combination of fuel sulfur levels that will minimize the fuel costs for these four Phase I units and maintain a sufficient surplus of emission allowances to cover uncertainties.

In addition to the CAAA Acid Rain requirements, the Company will continue to comply with the New Hampshire acid rain regulations that have been in effect since 1991. These regulations cap the total Merrimack 1 and 2, Newington, and the three Schiller units' annual SO_2 emissions at 55,150 tons.

The Massachusetts Acid Rain regulations require that, starting in 1995, WMECO and HWPCO units on the system have an average emissions rate of 1.2 lbs/MBtu. In calculating this rate the Company can take into account conservation credits and cogeneration installed in the period 1989-94. West Springfield 3 by virtue of using 1.0% sulfur oil and interruptible gas will comply. Mount Tom will likely comply by changing to a lower sulfur fuel.

Phase II

Phase II of the CAAA acid rain section begins in 2000 and affects all units greater than 25 MW. These units will require allowances starting in that year for all of their SO_2 emissions. These Phase II units will require CEMs to be installed and operating by 1/1/95 and permit applications to be submitted by 1/1/96. All affected units in Connecticut are already in compliance with Phase II by virtue of their use of fuel with 1.0% sulfur or less. In Massachusetts, West Springfield 3 is already in compliance, but Mount Tom will likely comply with a shift to a lower sulfur fuel (i.e. below 1.0%). The New Hampshire units at Merrimack and Newington stations will likely shift to lower sulfur fuels to comply with Phase II.

SO_2 Allowance Surplus

In Phase I the allowances granted to the four units appear to be sufficient for them to comply with an adequate margin. In Phase II the Company expects to have surplus allowances after accounting for a reasonable range of operational uncertainties. The Company is examining ways to maximize the benefit of this to the ratepayers and shareholders. This principally consists of ways to sell a portion of the surplus in a way that moderates the risks of the allowance market uncertainties.

NO_x Compliance

The Company is currently evaluating ways to achieve compliance with lower NO_x emission levels to help achieve attainment of the ozone standard under

Title I of the CAAA, and to comply with acid rain provisions under Title IV. The final state regulations for Title I NO_x are expected to be issued during 1993. The recent NO_x proposal in New Hampshire by PSNH and other parties will achieve about a 50% reduction in NO_x from PSNH units in the summer and a 30% reduction on an annual basis from 1994 through 1998. The proposal includes the possibility of a capacity reduction of about 25% in the summer months. For 1999 and beyond, NO_x emissions must be further reduced by additional pollution control equipment, repowering, or retirement.

The Connecticut and Massachusetts DEPs have issued draft regulations and held public hearings on NO_x emissions and on a system for banking and trading Emission Reduction Credits (ERCs). NU has been actively involved in developing those regulations to assure that a workable, consistent system for trading ERCs across the region is developed.

The Company expects to be in compliance with Title I by the required date, May 15, 1995. Additional NO_x reductions for acid rain compliance are unlikely since the NO_x compliance measures taken under Title I are expected to meet the Title IV requirements.

Other CAAA Requirements

Other portions of the CAAA are restrictions on mobile sources and required fuel changes. In Fairfield County, the Company will need to implement a 25% increase in employee commuter vehicle occupancy. Less polluting vehicles must be phased into the company fleet over time, which must in turn be fueled by cleaner fuels.

Air toxics is another major section of the CAAA but there are no regulations yet for electric utilities. Air toxics impacts are unknown at this time but they have the potential to be significant. The CAAA also requires CFCs and Halon to be phased out of production by 1996.

Environmental Externalities

The Massachusetts DPU established monetized values for environmental externalities in Docket 91-131. These are to be used in evaluating new resources in the Integrated Resource Planning Process. NU, along with other New England utilities, had argued strongly in that docket for externality values be properly based on damage costs. However the DPU's final values reflect their original approach based on control costs. Use of these values will cause a large distortion in relative economics of future resource options, and NU has joined in a National Coal Association, Massachusetts Electric Co., and Boston Edison Co. appeal of the DPU's decision in 91-131.

Neither Connecticut nor New Hampshire has a system of externalities for energy evaluations in place, but the Connecticut DPUC is required to explore this subject. A Connecticut Public Act requires the DPUC to conduct a study of external costs and benefits related to energy consumption and look into whether a system of allowances, offsets, or adders should be established when analyzing new energy projects. The DPUC must submit a report of its findings and recommendations to the Joint

Standing Committee of the General Assembly on or before 1/1/94. The Company will cooperate fully with the DPUC to efficiently explore this matter.

Availability and Price of Fuels

The principal fossil fuel options for long term supply are coal, oil, and natural gas. Renewable resources are expected to play a role, especially as newer technologies such as photovoltaics become more competitive through further progress in their development. The extent of renewable technology contributions will depend on availability of acceptable sites and their economics.

Coal will likely remain the most stable and economic fossil fuel but requires capital-intensive generating technologies and pollution control equipment to be feasible. Any CO_2 reduction efforts may add significant costs to using this fuel.

With increased availability and the CAAA push for cleaner SO_2 emissions, natural gas has become a popular choice for new generation. Whether gas will continue to be the preferred choice over the long term will depend on the reliability of its supply during times of system need.

Because of its major dependency on foreign sources and the availability of more secure fossil fuels on this continent, i.e., natural gas and coal, oil will not likely be an option for new utility supply except as a supplemental or backup fuel.

Technology Progress

While the progress in new technology can be projected, any unforeseen advances or delays can influence the availability and attractiveness of a specific supply technology for the long term. The Company continually monitors the progress of all practical supply options to stay abreast and alert to any opportunities for use of improved technologies in its service area. NU's Supply Screening document will be updated during 1993.

Existing Sites

The future solicitation of new supply resources will likely be through competitive RFPs. Such an environment may result in both proposed projects by third parties and utilities being selected to meet future needs. In either case, for projects of any significant size, i.e., greater than 50 MW, the availability of suitable sites will be critical. Therefore, existing sites with their established land use, environmental impacts, and existing transmission system interconnections will continue to be desired and very competitive locations for future electric generation plants. As the Company moves closer to its year of need, it will need to examine carefully its options at its existing sites and to plan for the continued use of these critical resources.

Nuclear Relicensing

NU operates five nuclear units: Millstone Units 1, 2, and 3 (in Connecticut); Connecticut Yankee (in Connecticut); and Seabrook (in New Hampshire). NU also has entitlements in two other nuclear units: Vermont Yankee and Maine Yankee.

The Nuclear Regulatory Commission (NRC), initially the Atomic Energy Commission (AEC), issued operating licenses that expired 40 years from the date of construction permit issuance. In more recent years, NRC practice has been to issue operating licenses valid for 40 years from operating license issue date, which adds at least several years to the length of actual plant operation. For those units whose licenses were based on construction permit issuance, the NRC has authorized amendments to cover the years of construction, if the unit's operator applies for the extension. Except for Maine Yankee, all of the units in which NU has entitlement have licenses that reflect the longer operating interval. These license expiration dates are given below:

Unit	License Expiration
Connecticut Yankee	06/29/2007
Maine Yankee	10/21/2008
Millstone 1	10/06/2010
Vermont Yankee	03/24/2012
Millstone 2	07/31/2015
Millstone 3	11/25/2025
Seabrook	10/17/2026

Beyond these license extensions that recapture the construction period, NU has not pursued nuclear plant license renewal (operation beyond 40 years) although this option remains open. In 1991, the NRC issued new regulations governing the license renewal process. In addition to reaffirming the continuation of rigorous review, oversight, inspection, and maintenance, licensees must demonstrate that any potential age-related degradation is identified and satisfactorily addressed.

The nuclear plants that NU operates have historically performed better than the industry average. However, in the past two years, nuclear plant performance at NU has not met NU's high standards. In response to this, NU has developed and is implementing a Performance Enhancement Program to improve regulatory and operating performance at the Connecticut Yankee and Millstone Stations. The program is focused on the improvement of the critical areas impacting the overall performance of the nuclear program.

The Company monitors the effectiveness of the process, initiatives, and programs under way at NU to achieve excellence. Performance is reviewed in detail periodically, with corrective action taken to change performance which shows signs of not achieving desired goals.

In addition, a pilot incentive program is in place for 1993 for key managers in the nuclear program. This program is designed to help focus Nuclear Group resources on the achievement of key operational performance and reliability results while at the same time meeting budget goals.

The collective objective of these programs is to restore the reliability of the NU generation units to the desired level.

TABLE IV-1

NORTHEAST UTILITIES WHOLLY-OWNED GENERATING UNITS
BY CATEGORY AND COMPANY AS OF JANUARY 1, 1993

This table shows the list of all wholly-owned generating units presently installed on the Northeast Utilities combined system, arranged in BASE LOAD, INTERMEDIATE, PEAKING, PUMPED STORAGE, and HYDRO categories. Base load units are typically operated around the clock, intermediate units are those used to supply additional load required over a substantial part of the day, and peaking units supply power usually during the weekday hours of highest demand. On occasion, some of the more efficient intermediate units operate as base load units, while others may be called upon to operate as peaking capacity. Accordingly, these categories are intended to be generally descriptive yet not definitive. Pumped storage units store low cost energy available during off-peak periods for re-use during high cost on-peak periods. Hydroelectric units may operate as base load, intermediate, or peaking capacity depending on the availability of water, which tends to vary seasonally. The ownership of all units is designated by operating company and location by town and state.

Deferred Retirement Units and Reactivated Units are listed separately. These units are operating beyond their original planned retirement dates. The decision to remove these units from service will depend on many factors.

In addition to the wholly-owned generating capacity listed in Table IV-1, the NU combined system has contractual interests in other generating capacity in New England by virtue of long- and short-term purchase contracts. A complete summation of net capacity available (including capacity purchases and sales) as of January 1, 1993, and as of August 1, 1993, is presented in Table IV-2.

TABLE IV-1
(Page 1 of 3)

NORTHEAST UTILITIES SYSTEM
WHOLLY OWNED GENERATING UNITS
BY CATEGORY AND COMPANY AS OF JANUARY 1, 1993 (NOTE 1)

	WINTER RATING (MW)	SUMMER RATING (MW)	YEAR INSTALLED	LOCATION	OWNERSHIP - % CL&P	WMECO	HWP	PSNH
BASE LOAD								
Nuclear								
Millstone Unit 1	659.50	641.03	1970	Waterford, CT	81.0	19.0		
Millstone Unit 2	874.50	873.10	1975	Waterford, CT	81.0	19.0		
Nuclear Subtotal	1,534.00	1,514.13						
Fossil Steam								
Middletown Unit 3	245.00	236.00	1964	Middletown, CT	100.0			
Mount Tom	147.00	146.00	1960	Holyoke, MA			100.0	
Merrimack Unit 1	113.50	112.50	1960	Bow, NH				100.0
Merrimack Unit 2	320.00	320.00	1968	Bow, NH				100.0
Fossil Steam Subtotal	825.50	814.50						
Base Load Total	2,359.50	2,328.63						
INTERMEDIATE								
Fossil Steam								
Devon Unit 7	109.00	107.00	1956	Milford, CT	100.0			
Devon Unit 8	109.00	107.00	1958	Milford, CT	100.0			
Middletown Unit 2	120.00	117.00	1958	Middletown, CT	100.0			
Middletown Unit 4	400.00	400.00	1973	Middletown, CT	100.0			
Montville Unit 5	82.00	81.00	1954	Montville, CT	100.0			
Montville Unit 6	410.00	410.00	1971	Montville, CT	100.0			
Norwalk Harbor Unit 1	164.00	162.00	1960	Norwalk, CT	100.0			
Norwalk Harbor Unit 2	172.00	168.00	1963	Norwalk, CT	100.0			
West Springfield Unit 3	108.30	107.30	1957	W. Springfield, MA		100.0		
Schiller Unit 4	47.50	47.50	1952	Portsmouth, NH				100.0
Schiller Unit 5	49.60	49.60	1955	Portsmouth, NH				100.0
Schiller Unit 6	48.00	48.00	1957	Portsmouth, NH				100.0
Newington Unit 1	406.00	406.00	1974	Newington, NH				100.0
Subtotal	2,225.40	2,210.40						
Intermediate Total	2,225.40	2,210.40						
PEAKING								
Gas Turbine and Diesel								
Cos Cob Units 10,11 and 12	68.60	54.65	1969	Greenwich, CT	100.0			
Devon Unit 10	19.20	17.20	1966	Milford, CT	100.0			
Middletown Unit 10	22.00	17.20	1966	Middletown, CT	100.0			
Montville Units 10 & 11	5.50	5.50	1967	Montville, CT	100.0			
Norwalk Harbor Unit 10	17.00	12.30	1966	Norwalk, CT	100.0			
South Meadow Units 11-14	195.60	155.80	1970	Hartford, CT	100.0			
West Springfield Unit 10	22.00	14.30	1968	W. Springfield, MA		100.0		
Swans Falls Units 1-3	3.00	3.00	1948	Fryeburg, ME				100.0
Lost Nation CT	18.30	13.65	1969	Northumberland, NH				100.0
Schiller Jet	22.00	17.00	1970	Portsmouth, NH				100.0
Merrimack Jet 1-2	44.60	34.00	1968,1969	Bow, NH				100.0
White Lake Jet	22.15	18.70	1968	Tamworth, NH				100.0
Subtotal	459.95	363.30						

TABLE IV-1
(Page 2 of 3)

NORTHEAST UTILITIES SYSTEM
WHOLLY OWNED GENERATING UNITS
BY CATEGORY AND COMPANY AS OF JANUARY 1, 1993 (NOTE 1)

	WINTER RATING (MW)	SUMMER RATING (MW)	YEAR INSTALLED	LOCATION	OWNERSHIP - % CL&P	WMECO	HWP	PSNH
PEAKING (CON'T)								
Deferred Retirement Units:								
Doreen Unit 10	21.20	16.60	1969	Pittsfield, MA		100.0		
Franklin Drive Unit 10	22.00	17.20	1968	Torrington, CT	100.0			
Torrington Terminal Unit 10	21.80	17.20	1967	Torrington, CT	100.0			
Tunnel Unit 10	20.80	16.85	1969	Preston, CT	100.0			
Woodland Road Unit 10	21.20	16.60	1969	Lee, MA		100.0		
Subtotal	107.00	84.45						
Reactivated Units:								
Branford Unit 10	21.00	14.90	1969	Branford, CT	100.0			
Subtotal	21.00	14.90						
Gas Turbine and Diesel Subtotal	587.95	462.65						
Peaking Total	587.95	462.65						
PUMPED STORAGE								
Northfield Mt. Unit 1	270.00	270.00	1973	Erving, MA	81.0	19.0		
Northfield Mt. Unit 2	270.00	270.00	1973	Erving, MA	81.0	19.0		
Northfield Mt. Unit 3	270.00	270.00	1973	Erving, MA	81.0	19.0		
Northfield Mt. Unit 4	270.00	270.00	1972	Erving, MA	81.0	19.0		
Rocky River	30.35	29.35	1929	New Milford, CT	100.0			
Pumped Storage Total	1,110.35	1,109.35						

TABLE IV-1
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NORTHEAST UTILITIES SYSTEM
WHOLLY OWNED GENERATING UNITS
BY CATEGORY AND COMPANY AS OF JANUARY 1, 1993 (NOTE 1)

	WINTER RATING (MW)	SUMMER RATING (MW)	YEAR INSTALLED	LOCATION	OWNERSHIP - % CL&P	WMECO	HWP	PSNH
CONVENTIONAL HYDRO								
Bantam Unit 1	0.28	0.06	1905	Litchfield, CT	100.0			
Bulls Bridge Units 1-6	8.40	8.40	1903	New Milford, CT	100.0			
Cabot Units 1-6	53.00	53.00	1915,1916,1917	Montague, MA		100.0		
Dwight Units 2,3,4	1.70	1.52	1920	Chicopee, MA		100.0		
Falls Village Units 1-3	11.00	9.74	1914	Canaan, CT	100.0			
Gardners Falls Units 2-5	3.70	3.70	1904,1914,1925	Buckland, MA		100.0		
Holyoke Water Power Co. (NOTE 2)	43.56	43.56		Holyoke, MA			100.0	
Indian Orchard Units 3,4	3.70	3.70	1928	Springfield, MA		100.0		
Putts Bridge Units 2,3	4.10	3.97	1918	Ludlow, MA		100.0		
Red Bridge Units 3,4	4.50	4.50	1926,1934	Wilbraham, MA		100.0		
Robertsville Units 1,2	0.62	0.31	1924	Colebrook, CT	100.0			
Scotland Unit 1	2.20	1.67	1937	Windham, CT	100.0			
Shepaug Unit 1	43.40	42.95	1955	Southbury, CT	100.0			
Stevenson Units 1-4	28.90	28.95	1919,1936	Monroe, CT	100.0			
Taftville Units 1-5	2.03	2.03	1906,1926,1949	Norwich, CT	100.0			
Tunnel Units 1,2	2.10	1.42	1919,1949	Preston, CT	100.0			
Turners Falls Units 1-3,5,7	6.25	6.25	1905,1910,1913	Montague, MA		100.0		
Amoskeag	17.50	17.50	1923	Manchester, NH				100.0
Ayers Island	9.08	9.08	1925	New Hampton, NH				100.0
Canaan	1.10	1.10	1927	Canaan, VT				100.0
Eastman Falls 1-2	6.47	6.47	1937,1983	Franklin, NH				100.0
Garvins 1-4	10.55	10.55	1925,1981(1&2)	Bow, NH				100.0
Gorham	2.05	2.05	1920	Gorham, NH				100.0
Hookset	1.90	1.90	1927	Hooksett, NH				100.0
Jackman	3.55	3.60	1925	Hillsboro, NH				100.0
Smith	15.31	13.08	1948	Berlin, NH				100.0
Conventional Hydro Total	286.95	281.06						
NORTHEAST UTILITIES SYSTEM WHOLLY OWNED GENERATING CAPACITY EXCLUDING DEFERRED RETIREMENT UNITS AND REACTIVATED UNITS	6,442.15	6,292.74						
DEFERRED RETIREMENT UNITS GENERATING CAPACITY	107.00	84.45						
REACTIVATED UNITS GENERATING CAPACITY	21.00	14.90						
TOTAL GENERATING CAPACITY	6,570.15	6,392.09						

NOTES:
(1) This table does not reflect long-term or short-term capacity purchases or sales, life-of-unit contract sales, or a listing of generating units in which the merged system has joint ownership with other utilities. That information appears on TABLE IV-2.

(2) Holyoke Water Power Co. hydro units are powered from a common canal system. The units are dispatched together. The reported capabilities are the aggregate for the complex. The units' individual ratings and installation dates are:

Station/Unit		Name Plate Ratings(MW)	Year Installed
Beebe Holbrook	Units 1,2	0.60	1947, 1948
Boatlock	Units 1-3	2.90	1921, 1924, 1924
Chemical	Units 1,2	1.60	1935, 1935
Hadley Falls	Units 1,2	31.00	1952, 1983
Riverside	Units 4,5,7,8	7.00	1920, 1905, 1921, 1931
Skinner	Unit 1	0.30	1924

TABLE IV-2

NORTHEAST UTILITIES SYSTEM

NET CAPACITY AVAILABLE BY GENERATION AND SUPPLY CATEGORY
AS OF JANUARY 1, 1993, AND AUGUST 1, 1993

Table IV-2 identifies the Northeast Utilities actual net capacity available by generation and supply category as of January 1, 1993 (Winter 1992/1993) and August 1, 1993 (Summer 1993). It includes the Northeast Utilities system's wholly-owned capacity and entitlements in other New England units, together with contracted short-term capacity purchases and sales and life-of-unit contract sales with other utilities, and contracted non-utility generation. The item under each unit category entitled "Wholly Owned" refers to capacity totals for that category listed in Table IV-1.

TABLE IV-2
(Page 1 of 4)

NORTHEAST UTILITIES SYSTEM
NET CAPACITY AVAILABLE BY GENERATION AND
SUPPLY CATEGORY AS OF JANUARY 1, 1993 AND AUGUST 1, 1993 (NOTE 1)

BASE LOAD	Winter Rating 1992/93 (MW)	Summer Rating 1993 (MW)
Wholly Owned Nuclear:	1,534.00	1,514.13
Nuclear Entitlements:		
Millstone Unit 3	781.33	773.19
Connecticut Yankee, Haddam, CT	280.03	265.84
Vermont Yankee, Vernon, VT	72.73	69.46
Maine Yankee, Wiscasset, ME	153.91	152.16
Seabrook 1	455.74	455.74
Subtotal Nuclear	3,277.74	3,230.52
Millstone Unit 1 Sales to:		
Boston Edison	(30.00)	(29.16)
Canal Electric	(4.29)	(4.17)
Fitchburg	(2.15)	(2.09)
MMWEC	(3.76)	(3.65)
Montaup	(4.29)	(4.17)
NEPCO	(16.10)	(15.64)
UNITIL	(4.29)	(4.17)
Rowley	(0.03)	(0.03)
Millstone Unit 2 Sales to:		
Boston Edison	(30.44)	(30.39)
Canal Electric	(4.32)	(4.32)
Fitchburg	(2.18)	(2.17)
MMWEC	(3.81)	(3.80)
Montaup	(4.32)	(4.32)
NEPCO	(16.21)	(16.18)
UNITIL	(4.35)	(4.35)
Rowley	(0.03)	(0.03)
Millstone Unit 3 Sales to:		
Boston Edison	(59.62)	(59.00)
Canal Electric	(6.97)	(6.90)
Fitchburg	(3.49)	(3.45)
MMWEC	(6.10)	(6.04)
Montaup	(6.97)	(6.90)
NEPCO	(26.14)	(25.87)
UNITIL	(6.97)	(6.90)
Rowley	(0.03)	(0.03)
Seabrook Sale to Rowley	(0.03)	(0.03)
NHEC Buyback	25.00	25.00
Nuclear Life-of-Unit Contract Sales to CMEEC	(68.76)	(67.47)
Nuclear Life-of-Unit Contract Sales to Wallingford (NOTE 2)	(31.15)	(30.55)
EXCHANGES OF CAPACITY:		
Millstone Unit 1 From CMEEC	3.80	3.74
Net Nuclear Subtotal	2,959.74	2,917.48
Wholly Owned Fossil Steam:	825.50	814.50
Middletown Unit 3 Sales to:		
Canal Electric	(24.10)	(2.02)
Chicopee	(2.58)	(2.48)
Fitchburg	(1.05)	(1.01)
MMWEC	(1.84)	(1.77)
Montaup	(2.10)	(2.02)
NEPCO	(7.87)	(7.58)
UNITIL	(2.10)	(2.02)
Rowley	(0.08)	(0.08)
Merrimack Units 1 & 2 Sale to Rowley	(0.06)	(0.06)
Long-Term Fossil Sales:		
Merrimack Unit 2 Sale to VELCO	(100.00)	(100.00)
Fossil Steam Life-of-Unit Contract Sales to CMEEC	(9.48)	(9.13)
Fossil Steam Life-of-Unit Contract Sales to Wallingford (NOT	(9.62)	(9.27)
System Power Sale to CU	(5.00)	(5.00)
Net Fossil Subtotal	659.62	672.06
NET BASE LOAD TOTAL	3,619.36	3,589.54

TABLE IV-2
(Page 2 of 4)

NORTHEAST UTILITIES SYSTEM
NET CAPACITY AVAILABLE BY GENERATION AND
SUPPLY CATEGORY AS OF JANUARY 1, 1993 AND AUGUST 1, 1993 (NOTE 1)

	Winter Rating 1992/1993 (MW)	Summer Rating 1993 (MW)
INTERMEDIATE		
Wholly Owned Fossil Steam:		
Excluding Deferred Retirement Units	2,225.40	2,210.40
Subtotal	2,225.40	2,210.40
Fossil Steam Entitlements:		
Yarmouth Unit 4, Yarmouth, ME	19.46	19.32
Long-Term Fossil Sales:		
Newington Sale to CU	(2.50)	(2.50)
SHORT TERM SALES:		
Middletown Unit 2 Sales to:		
Chicopee	(1.26)	(1.23)
Rowley	(0.08)	(0.08)
Middletown Unit 4 Sales to:		
Canal Electric	(33.42)	(3.42)
Chicopee	(4.21)	(4.21)
Fitchburg	(1.71)	(1.71)
MMWEC	(3.00)	(3.00)
Montaup	(3.42)	(3.42)
NEPCO	(69.84)	(69.84)
UNITIL	(3.42)	(3.42)
Rowley	(0.30)	(0.30)
Montville Unit 5 Sales to:		
Chicopee	(1.33)	(1.32)
Montville Unit 6 Sales to:		
Canal Electric	(3.51)	(3.51)
Chicopee	(6.67)	(6.67)
Fitchburg	(1.75)	(1.75)
MMWEC	(3.07)	(3.07)
Montaup	(3.51)	(3.51)
NEPCO	(13.15)	(13.15)
UNITIL	(3.51)	(3.51)
Rowley	(0.30)	(0.30)
Newington Sale to Rowley	(0.08)	(0.08)
Yarmouth Unit 4 Sale to Rowley	(0.08)	(0.08)
Norwalk Harbor Unit 1 Sales to:		
Canal Electric	(1.40)	(1.39)
Fitchburg	(0.70)	(0.69)
MMWEC	(1.23)	(1.21)
Montaup	(1.40)	(1.39)
NEPCO	(5.27)	(5.20)
UNITIL	(1.40)	(1.39)
Rowley	(0.08)	(0.08)
Norwalk Harbor Unit 2 Sales to:		
Canal Electric	(1.47)	(1.44)
Fitchburg	(0.74)	(0.73)
MMWEC	(1.30)	(1.27)
Montaup	(1.47)	(1.44)
KEPCO	(5.52)	(5.39)
UNITIL	(1.49)	(1.45)
Rowley	(0.08)	(0.08)

TABLE IV-2
(Page 3 of 4)

NORTHEAST UTILITIES SYSTEM
NET CAPACITY AVAILABLE BY GENERATION AND
SUPPLY CATEGORY AS OF JANUARY 1, 1993 AND AUGUST 1, 1993 (NOTE 1)

	Winter Rating 1992/1993 (MW)		Summer Rating 1993 (MW)	
INTERMEDIATE (CON'T)				
Fossil Steam Life-of-Unit Contract Sales to CMEEC	(60.57)		(60.04)	
Fossil Steam Life-of-Unit Contract Sales to Wallingford (NOT	(63.63)		(62.73)	
System Sale to Bozrah	(7.67)		(7.67)	
EXCHANGES OF CAPACITY:				
Norwalk Harbor Unit 1 to CMEEC	(10.00)		(10.00)	
Norwalk Harbor Unit 2 to CMEEC	(10.00)		(10.00)	
New Haven Harbor from UI	35.00		25.00	
System Exchange from UI	0.00		25.00	
NET INTERMEDIATE FOSSIL STEAM TOTAL		1,944.31		1,976.06
PEAKING				
Wholly Owned Gas Turbines and Diesels:				
Excluding Deferred Retirement Units	459.95		363.30	
Deferred Retirement Units	107.00		84.45	
Reactivated Units	21.00		14.90	
Subtotal	587.95		462.65	
SHORT-TERM SALES:				
Cos Cob Units 10-12 Sales to:				
Canal Electric	(0.67)		(0.52)	
Fitchburg	(0.33)		(0.26)	
MMWEC	(0.59)		(0.46)	
Montaup	(0.67)		(0.52)	
NEPCO	(2.49)		(1.98)	
UNITIL	(0.67)		(0.53)	
South Meadow Units 11-14 Sales to:				
Canal Electric	(1.91)		(1.52)	
Chicopee	(16.00)		(12.74)	
Fitchburg	(0.96)		(0.76)	
MMWEC	(1.67)		(1.32)	
Montaup	(1.91)		(1.52)	
NEPCO	(7.11)		(5.67)	
UNITIL	(21.87)		(1.52)	
VEG&T	(7.99)		0.00	
Merrimack CT Units 1 & 2 Sale to Rowley	(0.70)		(0.53)	
Peaking Life-of-Unit Contract Sales to CMEEC	(2.46)		(2.03)	
Peaking Life-of-Unit Contract Sales to Wallingford (NOTE 2)	(7.99)		(6.39)	

TABLE IV-2
(Page 4 of 4)

NORTHEAST UTILITIES SYSTEM
NET CAPACITY AVAILABLE BY GENERATION AND
SUPPLY CATEGORY AS OF JANUARY 1, 1993 AND AUGUST 1, 1993 (NOTE 1)

	Winter Rating 1992/1993 (MW)		Summer Rating 1993 (MW)	
PEAKING (CON'T)				
EXCHANGES OF CAPACITY:				
South Norwich 1 From CMEEC	5.07		4.95	
South Norwich 2-5 From CMEEC	10.50		10.12	
Norwich Jet From CMEEC	0.63		1.94	
Cos Cob Units 10-12 to United Illuminating	(42.00)		(45.00)	
South Meadow Units 11-14 to United Illuminating	(42.00)		(75.00)	
Net Gas Turbine and Diesel Subtotal	444.17		321.39	
NET PEAKING FOSSIL TOTAL		444.17		321.39
PUMPED STORAGE				
	1,110.35		1,109.35	
Wholly Owned Pumped Storage:				
Northfield Units 1-4 Sales to:				
Boston Edison	(180.00)		(180.00)	
Canal Electric	(10.72)		(10.72)	
Fitchburg	(4.96)		(4.96)	
MMWEC	(8.68)		(8.68)	
Montaup	(10.72)		(10.72)	
NEPCO	(40.16)		(40.16)	
UNITIL	(9.92)		(9.92)	
Northfield Life-of-Unit Contract Sales to CMEEC	(12.60)		(12.60)	
Northfield Life-of-Unit Contract Sales to Wallingford (NOTE	(10.00)		(10.00)	
NET PUMPED STORAGE TOTAL		822.59		821.59
CONVENTIONAL HYDRO				
	286.95		281.06	
Wholly Owned Conventional Hydro:				
Conv. Hydro Life-of-Unit Contract Sales to CMEEC	(6.64)		(6.61)	
Conv. Hydro Life-of-Unit Contract Sales to Wallingford (NOTE	(3.01)		(2.99)	
Cobble Mountain Purchase, Springfield, MA	33.96		33.98	
NET CONVENTIONAL HYDRO TOTAL		311.26		305.44
COGENERATION AND SMALL POWER PRODUCTION				
	635.61		652.25	
Capacity Committed to NU: NET COGENERATION AND SMALL POWER PRODUCTION		635.61		652.25
NEW YORK POWER AUTHORITY (NYPA)	2.89		3.39	
NET NYPA		2.89		3.39
NORTHEAST UTILITIES COMBINED SYSTEM TOTAL NET CAPACITY AVAILABLE		7,780.19		7,669.66

NOTES:

(1) Figures in parenthesis are negative and indicate capacity sales from the NU system.
(2) The Wallingford loads have not been included in the load forecast.
It is expected that the agreement will be finalized in 1993.

TABLE IV-3

NORTHEAST UTILITIES SYSTEM
GENERATING UNITS UNDER CONSTRUCTION
AS OF JANUARY 1, 1993

NONE

TABLE IV-4

NORTHEAST UTILITIES SYSTEM
ASSUMED DEACTIVATIONS AND RETIREMENTS OF GENERATING UNITS
1993-2012

Listed below are existing generating units which will become candidates for deactivation or retirement during the forecast period. Also provided are their current winter MW rating, location, type, ownership percentage, and the assumed date of deactivation or retirement, as reflected in Table IV-6.

It is important to note that these dates are accounting deactivation dates, not engineering retirement dates. The physical conditions of the units will allow them, with routine maintenance and repair, to operate beyond the assumed accounting deactivation dates. NU retired the internal combustion units Silver Lake Units 10-13 and Tracy on May 1, 1992.

The current dates of deactivation for units is based upon the NU system's forecasted reserve requirements, its present commitments for capacity sales, and the regional load and capacity outlook. Changes in either NU's or the regions' load and capacity situation could affect the deactivation dates shown. Consequently, the timing and order of such deactivations will remain under continual review and, as circumstances change, this schedule could be altered.

As discussed in Chapter 1, the Company continues to evaluate the continued operation of its units. These evaluations may require changes to this list in the future.

Deferred Retirement Units	Unit No.	Winter MW Rating	Location	Type	Ownership Percentage	Assumed Date of Retirement or Deactivated Reserve
Tunnel	10	20.8	Preston, CT	Jet Turbine	CL&P- 100.0	05/01/1996
Woodland Road	10	21.2	Lee, MA	Jet Turbine	WMECO-100.0	05/01/1996
Torrington Terminal	10	21.8	Torrington, CT	Jet Turbine	CL&P- 100.0	05/01/1996
Franklin Drive	10	22.0	Torrington, CT	Jet Turbine	CL&P- 100.0	05/01/1996
Doreen	10	21.2	Pittsfield, MA	Jet Turbine	WMECO-100.0	05/01/1996
Reactivated Unit						
Branford	10	21.0	Branford, CT	Jet Turbine	CL&P -100.0	05/01/1996
Deactivations						
Montville	5	82.0	Montville, CT	Steam	CL&P- 100.0	01/01/1995*
Montville	6	410.0	Montville, CT	Steam	CL&P- 100.0	01/01/1995*
Montville	10&11	5.5	Montville, CT	Diesel	CL&P- 100.0	01/01/1995*

*For planning and budgeting purposes, these units will be reactivated on 11/01/98.

Nuclear unit retirement dates generally correspond to operating license expirations. Analyses of life extension are required to determine whether or not these units would retire on these dates.

Other Wholly-Owned Units	Unit No.	Winter MW Rating	Location	Type	Ownership Percentage	Assumed Retirement Date
Swans Falls	1-3	3.0	Fryeburg, ME	Diesel Engine	PSNH-100.0	11/01/1993
Millstone	1	659.5	Waterford, CT	Nuclear	CL&P -77.5** WMECO- 19.0	10/06/2010

**CL&P originally owned 81% of this unit. CMEEC negotiated a long-term purchase for 3.4936 percent ownership entitlement in this unit.

Life of Unit Entitlements

Connecticut Yankee	590.0	Haddam Neck, CT	Nuclear	CL&P - 33.0 WMECO- 9.5 PSNH - 5.0	06/29/2007
Maine Yankee	880.0	Wiscasset, ME	Nuclear	CL&P - 10.3 WMECO- 2.7 PSNH - 4.5	10/[illegible]/2008
Vermont Yankee	519.3	Vernon, VT	Nuclear	CL&P - 8.2 WMECO- 2.3 PSNH - 3.6	03/24/2012

TABLE IV-5

NORTHEAST UTILITIES SYSTEM
1993-2012 FORECASTED NEW GENERATING ADDITIONS

Forecasted New Generating Additions

NONE CONTEMPLATED DURING THE 1993-2012 FORECAST PERIOD.

TABLE IV-6

NORTHEAST UTILITIES SYSTEM
1993-2012 FORECAST OF
GENERATING CAPACITY AT THE TIME OF
WINTER AND SUMMER PEAK

The format of Table IV-6 develops the total NET CAPACITY AVAILABLE and relates this capacity to the peak system demand forecast for 1993-2012, as given in Chapter II.

NET CAPACITY AVAILABLE is made up of existing wholly owned generating units as detailed in Table IV-1, generating additions as shown in Table IV-3, the NU system's entitlements in other units, and the NU system's share of the capacity from exchange and purchase contracts with other utilities and non-utility generators like those shown in Table IV-2.

This subtotal is then reduced by assumed retirements as shown in Table IV-4, sales under capacity exchange contracts and long-term and short-term contract sales like those shown in Table IV-2, resulting in NET CAPACITY AVAILABLE to meet system peak load requirements.

NU SYSTEM ENTITLEMENTS IN OTHER UNITS represent the system's entitlements in Millstone Unit 3, Seabrook 1, Yarmouth 4, and other New England Yankee nuclear units. The Yankee entitlements shown are a result of power purchase contracts with each of the Yankee corporations. The purchase contracts are for the life of the unit. This line item decreases to reflect license expirations as shown in Table IV-4. The system companies also have a stock ownership in each of the Yankee companies generally proportional to their entitlements in the units.

CAPACITY EXCHANGES: Itemized in this category are agreements to exchange entitlements in the Northeast Utilities system units for entitlements of capacity in other units. These arrangements are shown as RETURN OF CAPACITY EXCHANGES and CAPACITY EXCHANGES. These are not exchanges in ownership of a unit, but rather contractual exchanges in the unit's output, designed to accommodate short-term surpluses and shortfalls in the different generating mix of each system. The purpose of an exchange-return arrangement is not only to improve a system's generation mix, resulting in a more economic dispatch and lower costs, but also to spread the risk of outages by reducing the dependence of a system on a particular generating unit. The NU system exchanges capacity on a week-to-week or month-to-month basis to achieve overall system economies.

PURCHASES: The entries in this category include the Cobble Mountain hydroelectric facility, the NU system's share of Connecticut's allocation associated with the St. Lawrence Hydroelectric Project as operated by the New York Power Authority (NYPA), short-term system purchases from sources outside of New England which are being made to reduce customers' costs, and capacity purchased from cogeneration and small power production projects for which the system has regulatory approval (including the results of the 54 MW WMECO solicitation). Additional projects may become available in the period covered by this report. Purchases from outside of New England are shown net of transmission losses.

DEACTIVATIONS/ RETIREMENTS: This category is comprised of the "deferred retirement units," the "reactivated units," and "other wholly-owned units" details for which are shown on Table IV-4. The amounts shown are based on assumptions current as of this forecast preparation. Consequently, the timing and amount of deactivations will be under continual review, and as circumstances change, the schedule will be altered.

CAPACITY SALES: The first item refers to life-of-unit contracts from certain Northeast Utilities system generating units including the New England Yankee nuclear units to the Connecticut Municipal Electric Energy Cooperative (CMEEC) and to Wallingford. Wallingford's load has been removed from the load forecast. The sales agreement is expected to be finalized in 1993.

The other item under this heading refers to contracts of varying durations with other utilities.

Similar long-term sales not known at this time may be made for periods covered by this report.

NORTHEAST UTILITIES SYSTEM CAPACITY SITUATION 1993-2012: Table IV-6 summarizes the twenty-year load and capacity situation for the system during the winter and summer peak periods of 1993 through 2012. The table also shows the system's reserve margin expressed in megawatts and as a percent of forecasted coincident peak loads. Not shown on the table are the NU system's commitments to the Hydro-Quebec Phase I and II contracts, interruptible load contracts, and load control measures. These elements of the resource plan will reduce forecasted reserve requirements.

TABLE IV-6
(PAGE 1 OF 5)

NORTHEAST UTILITIES SYSTEM
1993-2012 FORECAST OF CAPACITY AT THE TIME OF WINTER AND SUMMER PEAK
(AS OF JANUARY 1, 1993)

	WINTER 1992/93	SUMMER 1993	WINTER 1993/94	SUMMER 1994	WINTER 1994/95	SUMMER 1995	WINTER 1995/96	SUMMER 1996	WINTER 1996/97	SUMMER 1997
EXISTING WHOLLY OWNED GENERATION										
EXCLUDING DEFERRED RETIREMENT UNITS	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74
DEFERRED RETIREMENT UNITS	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45
REACTIVATED UNITS	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90
SUBTOTAL EXISTING WHOLLY OWNED GENERATION	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09
NU SYSTEM ENTITLEMENTS IN OTHER UNITS										
Millstone Unit 3	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19
Seabrook Unit 1	455.74	455.74	455.74	460.48	460.48	460.48	460.48	460.48	460.48	460.48
Existing Yankee Units	506.67	487.47	506.67	487.47	506.67	487.47	506.67	487.47	506.67	487.47
Yarmouth 4	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32
RETURN OF CAPACITY EXCHANGES										
CMEEC (NOTE 1)	20.00	20.75	20.00	20.75	20.00	20.75	20.00	20.75	0.00	0.00
United Illum. (NOTE 2)	35.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
PURCHASES										
Cobble Mountain	33.96	33.98	33.96	33.98	33.96	33.98	33.96	33.98	33.96	33.98
NHEC Buyback	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
NYPA (NOTE 3)	2.89	3.39	3.39	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Cogeneration and Small Power Production	635.61	652.25	689.61	652.25	689.61	665.75	703.11	665.75	703.11	665.75
SUBTOTAL	9,085.81	8,91[illegible].18	9,155.31	8,918.24	9,160.37	8,931.74	9,173.87	8,931.74	9,153.87	8,910.99
RETIREMENTS/DEACTIVATIONS (NOTE 4)										
Deferred Retirement Units	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(84.45)	(107.00)	(84.45)
Reactivated Units	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(14.90)	(21.00)	(14.90)
Other wholly-owned units	0.00	0.00	(3.00)	(3.00)	(500.50)	(499.50)	(500.50)	(499.50)	(500.50)	(499.50)
RETIREMENTS/DEACTIVATIONS SUBTOTAL	0.00	0.00	(3.00)	(3.00)	(500.50)	(499.50)	(500.50)	(598.85)	(628.50)	(598.85)
CAPACITY EXCHANGES										
CMEEC (NOTE 1)	(20.00)	(20.00)	(20.00)	(20.00)	(20.00)	(20.00)	(20.00)	(20.00)	0.00	0.00
United Illum. (NOTE 2)	(84.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)
CAPACITY SALES										
Life of Unit Contracts	(285.91)	(279.81)	(285.91)	(279.81)	(266.63)	(260.55)	(266.63)	(260.55)	(266.63)	(260.55)
Other	(915.71)	(823.71)	(559.68)	(549.31)	(329.04)	(323.34)	(265.91)	(260.22)	(275.91)	(270.22)
SUBTOTAL (Long/Short-Term Sales)	(1,305.62)	(1,243.52)	(985.59)	(969.12)	(735.67)	(723.89)	(672.53)	(660.76)	(662.53)	(650.76)
NET CAPACITY AVAILABLE	7,780.19	7,669.66	8,166.72	7,946.12	7,924.20	7,708.35	8,000.84	7,672.13	7,862.84	7,661.38
PEAK LOAD (NOTE 5)										
Estimated Peak Load	6,000.00	6,069.00	6,189.00	6,197.00	6,2[illegible]	6,304.00	6,431.00	6,453.00	6,541.00	6,594.00
RESERVE - MW (NOTE 6)	1,780.19	1,600.66	1,977.72	1,749.12	1,628.20	1,404.35	1,569.84	1,219.13	1,321.84	1,067.38
TOTAL RESERVE - %	29.67	26.37	31.96	28.23	25.86	22.28	24.41	18.89	20.21	16.19

TABLE IV-6
(PAGE 2 OF 5)

NORTHEAST UTILITIES SYSTEM
1993-2012 FORECAST OF CAPACITY AT THE TIME OF WINTER AND SUMMER PEAK
(AS OF JANUARY 1, 1993)

	WINTER 1997/98	SUMMER 1998	WINTER 1998/99	SUMMER 1999	WINTER 1999/00	SUMMER 2000	WINTER 2000/01	SUMMER 2001	WINTER 2001/02	SUMMER 2002
EXISTING WHOLLY OWNED GENERATION EXCLUDING DEFERRED RETIREMENT UNITS	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74
DEFERRED RETIREMENT UNITS	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45
REACTIVATED UNITS	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90
SUBTOTAL EXISTING WHOLLY OWNED GENERATION	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09
NU SYSTEM ENTITLEMENTS IN OTHER UNITS										
Millstone Unit 3	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19
Seabrook Unit 1	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48
Existing Yankee Units	506.67	487.47	506.67	487.47	506.67	487.47	506.67	487.47	506.67	487.47
Yarmouth 4	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32
RETURN OF CAPACITY EXCHANGES										
CMEEC (NOTE 1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United Illum. (NOTE 2)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	0.00	0.00
PURCHASES										
Cobble Mountain	33.96	33.98	33.96	33.98	33.96	33.98	33.96	33.98	33.96	33.98
NHEC Buyback	25.00	25.00	25.00	25.00	25.00	0.00	0.00	0.00	0.00	0.00
NYPA (NOTE 3)	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Cogeneration and Small Power Production	703.11	665.75	703.11	665.75	703.11	665.75	703.11	665.75	700.52	663.16
SUBTOTAL	9,153.87	8,910.99	9,153.87	8,910.99	9,153.87	8,885.99	9,128.87	8,885.99	9,076.28	8,833.40
RETIREMENTS/DEACTIVATIONS (NOTE 4)										
Deferred Retirement Units	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)
Reactivated Units	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)
Other wholly-owned units	(500.50)	(499.50)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
RETIREMENTS/DEACTIVATIONS SUBTOTAL	(628.50)	(598.85)	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)
CAPACITY EXCHANGES										
CMEEC (NOTE 1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United Illum. (NOTE 2)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	(120.00)	0.00	0.00
CAPACITY SALES										
Life of Unit Contracts	(266.63)	(260.55)	(285.87)	(279.80)	(285.87)	(279.75)	(285.87)	(279.75)	(285.87)	(279.75)
Other	(162.46)	(61.75)	(63.86)	(63.15)	(44.05)	(43.64)	(44.05)	(43.64)	(29.05)	(28.64)
SUBTOTAL (Long/Short-Term Sales)	(549.08)	(442.29)	(469.73)	(462.95)	(449.92)	(443.40)	(449.92)	(443.40)	(314.92)	(308.40)
NET CAPACITY AVAILABLE	7,976.29	7,869.85	8,553.14	8,345.69	8,57[illegible]	8,340.24	8,547.95	8,340.24	8,630.36	8,422.65
PEAK LOAD (NOTE 5)										
Estimated Peak Load	6,658.00	6,717.00	6,767.00	6,831.00	6,839.00	6,885.00	6,871.00	6,959.00	6,920.00	7,022.00
RESERVE - MW (NOTE 6)	1,318.29	1,152.85	1,786.14	1,514.69	1,733.95	1,455.24	1,676.95	1,381.24	1,710.36	1,400.65
TOTAL RESERVE - %	19.80	17.16	26.39	22.17	25.35	21.14	24.41	19.85	24.72	19.95

TABLE IV-6
(PAGE 3 OF 5)

NORTHEAST UTILITIES SYSTEM
1993-2012 FORECAST OF CAPACITY AT THE TIME OF WINTER AND SUMMER PEAK
(AS OF JANUARY 1, 1993)

	WINTER 2002/03	SUMMER 2003	WINTER 2003/04	SUMMER 2004	WINTER 2004/05	SUMMER 2005	WINTER 2005/06	SUMMER 2006	WINTER 2006/07	SUMMER 2007
EXISTING WHOLLY OWNED GENERATION EXCLUDING DEFERRED RETIREMENT UNITS	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74
DEFERRED RETIREMENT UNITS	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45
REACTIVATED UNITS	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90
SUBTOTAL EXISTING WHOLLY OWNED GENERATION	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09
NU SYSTEM ENTITLEMENTS IN OTHER UNITS										
Millstone Unit 3	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19
Seabrook Unit 1	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48
Existing Yankee Units	506.67	487.47	506.67	487.47	506.67	487.47	506.67	487.47	506.67	221.61
Yarmouth 4	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32
RETURN OF CAPACITY EXCHANGES										
CMEEC (NOTE 1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United Illum. (NOTE 2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PURCHASES										
Cobble Mountain	33.96	33.98	33.96	33.98	33.96	33.98	33.96	33.96	33.96	33.98
NHEC Buyback	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NYPA (NOTE 3)	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Cogeneration and Small Power Production	700.52	663.16	700.52	663.16	700.52	662.24	692.98	643.63	[illegible]	[illegible]
SUBTOTAL	9,076.28	8,833.40	9,076.28	8,833.40	9,076.28	8,832.48	9,068.74	8,813.87	[illegible]	[illegible]
RETIREMENTS/DEACTIVATIONS (NOTE 4)										
Deferred Retirement Units	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)
Reactivated Units	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)
Other wholly-owned units	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
RETIREMENTS/DEACTIVATIONS SUBTOTAL	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)
CAPACITY EXCHANGES										
CMEEC (NOTE 1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United Illum. (NOTE 2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPACITY SALES										
Life of Unit Contracts	(285.87)	(279.75)	(285.87)	(279.75)	(285.87)	(279.75)	(285.87)	(279.75)	(285.87)	(271.14)
Other	(25.21)	(24.80)	(25.21)	(24.80)	(25.21)	(24.80)	(10.00)	(9.82)	0.00	0.00
SUBTOTAL (Long/Short-Term Sales)	(311.08)	(304.56)	(311.08)	(304.56)	(311.08)	(304.56)	(295.87)	(289.58)	(285.87)	(271.14)
NET CAPACITY AVAILABLE	8,634.20	8,426.49	8,634.20	8,426.49	8,634.20	8,425.57	8,641.87	8,421.94	8,634.73	8,159.54
PEAK LOAD (NOTE 5)										
Estimated Peak Load	6,986.00	7,099.00	7,064.00	7,202.00	7,154.00	7,279.00	7,232.00	7,358.00	7,378.00	7,498.00
RESERVE - MW (NOTE 6)	1,648.20	1,327.49	1,570.20	1,224.49	1,480.20	1,146.57	1,409.87	1,063.94	1,256.73	661.54
TOTAL RESERVE - %	23.59	18.70	22.23	17.00	20.69	15.75	19.49	14.46	17.03	8.82

TABLE IV-6
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NORTHEAST UTILITIES SYSTEM
1993-2012 FORECAST OF CAPACITY AT THE TIME OF WINTER AND SUMMER PEAK
(AS OF JANUARY 1, 1993)

	WINTER 2007/08	SUMMER 2008	WINTER 2008/09	SUMMER 2009	WINTER 2009/10	SUMMER 2010	WINTER 2010/11	SUMMER 2011	WINTER 2011/12	SUMMER 2012
EXISTING WHOLLY OWNED GENERATION										
EXCLUDING DEFERRED RETIREMENT UNITS	6,442.15	6,292.74	6,442.15	6,292.74	6,442.15	6,292.74	5,782.65	5,651.71	5,782.65	5,651.71
DEFERRED RETIREMENT UNITS	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45	107.00	84.45
REACTIVATED UNITS	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90	21.00	14.90
SUBTOTAL EXISTING WHOLLY OWNED GENERATION	6,570.15	6,392.09	6,570.15	6,392.09	6,570.15	6,392.09	5,910.65	5,751.06	5,910.65	5,751.06
NU SYSTEM ENTITLEMENTS IN OTHER UNITS										
Millstone Unit 3	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19	781.33	773.19
Seabrook Unit 1	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48	460.48
Existing Yankee Units	226.64	221.63	72.73	69.46	72.73	71.89	72.73	71.89	72.73	0.00
Yarmouth 4	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32	19.46	19.32
RETURN OF CAPACITY EXCHANGES										
CMEEC (NOTE 1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United Illum. (NOTE 2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PURCHASES										
Cobble Mountain	33.96	33.98	33.96	33.98	33.96	33.98	33.96	33.98	33.96	33.98
NHEC Buyback	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NYPA (NOTE 3)	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Cogeneration and Small Power Production	617.04	564.83	522.20	440.95	418.20	402.95	364.20	348.95	300.49	284.85
SUBTOTAL	8,712.77	8,469.23	8,464.02	8,193.19	8,360.02	8,157.62	7,646.52	7,462.59	7,582.81	7,326.59
RETIREMENTS/DEACTIVATIONS (NOTE 4)										
Deferred Retirement Units	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)	(107.00)	(84.45)
Reactivated Units	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)	(21.00)	(14.90)
Other wholly-owned units	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
RETIREMENTS/DEACTIVATIONS SUBTOTAL	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)	(131.00)	(102.35)
CAPACITY EXCHANGES										
CMEEC (NOTE 1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United Illum. (NOTE 2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPACITY SALES										
Life of Unit Contracts	(276.80)	(271.14)	(272.66)	(267.05)	(272.66)	(267.05)	(249.62)	(244.65)	(249.62)	(242.78)
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SUBTOTAL (Long/Short-Term Sales)	(276.80)	(271.14)	(272.66)	(267.05)	(272.66)	(267.05)	(249.62)	(244.65)	(249.62)	(242.78)
NET CAPACITY AVAILABLE	8,304.97	8,095.74	8,060.36	7,823.79	7,956.36	7,788.22	7,265.90	7,115.59	7,202.19	6,981.46
PEAK LOAD (NOTE 5)										
Estimated Peak Load	7,533.00	7,639.00	7,682.00	7,792.00	7,833.00	7,948.00	7,967.00	8,092.00	8118	8241
RESERVE - MW (NOTE 6)	771.97	456.74	378.36	31.79	123.36	(159.78)	(701.10)	(976.41)	(915.81)	(1,259.54)
TOTAL RESERVE - %	10.25	5.98	4.93	0.41	1.57	(2.01)	(8.80)	(12.07)	(11.28)	(15.28)

TABLE IV-6
(PAGE 5 OF 5)

NORTHEAST UTILITIES SYSTEM
1993-2012 FORECAST OF CAPACITY AT THE TIME OF WINTER AND SUMMER PEAK
(AS OF JANUARY 1, 1993)

NOTES:

(1) This contract consists of an exchange of CMEEC's entitlements in Millstone 1, South Norwalk 1, South Norwalk 2-5, and Norwich Jet for entitlements in Norwalk Harbor 1&2. Details regarding the megawatt levels for specific units are shown in Table IV-2.

(2) This contract is an exchange of United Illuminating's entitlement in Bridgeport Harbor 3 for entitlements in Cos Cob 10-12 and South Meadow 11-14. Details regarding the megawatt levels for specific units are shown in Table IV-2.

(3) CL&P's contract for NYPA power ends June 30, 2001. It is assumed that CL&P will continue to receive the same share of NYPA power beyond the end of the current contract period (Winter 1994/1995) as it currently does in Winter 1994/1995.

(4) As per the assumed retirement/deactivation schedule shown on Table IV-4.

(5) 1992/93 winter peak load is preliminary. Peak loads shown are consistent with the data shown on Tables II-1 and II-2 of Chapter II.

(6) These reserves do not include the effects of interruptible service contracts, load control devices, or NU's participation in the Hydro Quebec interconnection.

TABLE IV-7
EXISTING CUSTOMER OWNED FACILITIES 1 MW AND ABOVE PROVIDING GENERATION TO THE NORTHEAST UTILITIES SYSTEM DURING 1992

PROJECT NAME	LOCATION	(1) FACILITY TYPE	FUEL SOURCE	BY-PRODUCT OF FUEL CONSUMPTION	ESTIMATED CAPACITY KW	NEPEX MAX CLAIMED CAPABILITY WINTER	NEPEX MAX CLAIMED CAPABILITY SUMMER
FACILITIES UNDER LONG TERM CONTRACT/RATE ORDER (2)							
AES	Montville, CT	COGEN	Coal	Steam	181,000	181,000	181,000
G. Fox	Hartford, CT	COGEN	Gas	Steam	4,100	4,100	3,320
Capitol District	Hartford, CT	COGEN	Gas	Steam	45,000	64,690	50,240
C.H. Dexter	Windsor Locks, CT	COGEN	Gas	Steam	39,000	39,000	38,000
Hartford Hospital	Hartford, CT	COGEN	Gas	Steam	10,150	10,150	9,970
O'Brien	Hartford, CT	COGEN	Gas	Steam	54,000	54,000	54,000
Hosiery Mill Dam	Hillsboro, NH	SPP	Hydro	–	1,250	N/A	N/A
Lochmere Dam	Belmont, NH	SPP	Hydro	–	1,000	N/A	N/A
Great Falls Lower	Somersworth, NH	SPP	Hydro	–	1,100	N/A	N/A
Mine Falls	Nashua, NH	SPP	Hydro	–	3,000	1,840	0
Clement Dam	Tilton, NH	SPP	Hydro	–	2,400	2,400	920
Newfound Hydro	Bristol, NH	SPP	Hydro	–	1,400	N/A	N/A
Rollinsford Hydro	Rollinsford, NH	SPP	Hydro	–	1,500	N/A	N/A
Pembroke Hydro	Pembroke, NH	SPP	Hydro	–	2,800	1,800	210
Briar Hydro	Concord, NH	SPP	Hydro	–	6,000	3,170	880
Penacook Upper Falls	Concord, NH	SPP	Hydro	–	3,020	2,390	740
Penacook Lower Falls	Concord, NH	SPP	Hydro	–	4,000	2,880	900
Errol Dam	Errol, NH	SPP	Hydro	–	3,000	3,000	2,870
River Bend Hydro	Franklin, NH	SPP	Hydro	–	1,7[illegible]	1,700	710
Greggs Falls	Goffstown, NH	SPP	Hydro	–	3,512	1,480	290
Spaulding Hydro	Milton, NH	SPP	Hydro	–	1,510	1,220	400
Kinneytown B	Seymour, CT	SPP	Hydro	–	1,500	N/A	N/A
Colebrook	Colebrook, CT	SPP	Hydro	–	3,000	N/A	N/A
Derby Dam	Shelton, CT	SPP	Hydro	–	6,900	7,050	7,050
Goodwin Dam	Hartland, CT	SPP	Hydro	–	3,294	N/A	N/A
BHB Quinebaug	Danielson, CT	SPP	Hydro	–	2,161	2,810	940
Salmon Falls Hydro	S.Berwick, ME	SPP	Hydro	–	1,200	N/A	N/A
New Milford	New Milford, CT	SPP	Methane	–	3,000	2,590	2,590
WES Concord MSW	Penacook, NH	SPP	MSW	–	13,200	12,340	12,190
Springfield	Agawam, MA	SPP	Refuse	Steam	6,000	6,000	6,000
Mid-CT CRRA	Hartford, CT	SPP	Refuse	Steam	63,710	63,710	64,100
Windham	Windham, CT	SPP	Refuse	–	1,500	N/A	N/A
Preston (SCRRRA)	Preston, CT	SPP	Refuse	–	13,850	13,850	9,880
Bristol RRF	Bristol, CT	SPP	Refuse	–	13,200	13,200	13,200
Wallingford RRF	Wallingford, CT	SPP	Refuse	Steam	6,900	6,900	6,350
Exeter	Sterling, CT	SPP	Tires	–	26,000	26,000	26,000
Whitefield Power	Whitefield, NH	SPP	Wood	–	13,800	13,800	13,800
Bethlehem Power	Bethlehem, NH	SPP	Wood	–	15,000	15,000	15,000
Alexandria Power	Alexandria, NH	SPP	Wood	–	15,000	15,000	15,000
Concord Steam (wood)	Concord, NH	COGEN	Wood	Steam	1,300	1,340	0
Bridgewater Power	Bridgewater, NH	SPP	Wood	–	15,000	15,000	15,000
Hemphill Power	Springfield, NH	SPP	Wood	–	13,800	13,800	13,800
Bio-Energy (wood)	Hopkinton(West), NH	COGEN	Wood	Steam	9,000	9,000	9,000
Timco (wood)	Barnstead(Center), NH	COGEN	Wood	Steam	4,800	3,800	4,100
Tamworth Power	Tamworth, NH	SPP	Wood	–	20,000	20,000	20,000
				SUBTOTAL	643,447	635,610	598,250
FACILITIES NOT UNDER LONG TERM CONTRACT/RATE ORDER (3)							
Monsanto	Springfield, MA	COGEN	Coal	Steam	5,700	N/A	N/A
Pratt & Whitney	E. Hartford, CT	COGEN	Gas	Steam	26,000	N/A	N/A
Farmington River Power	Windsor, CT	SPP	Hydro	–	9,450	N/A	N/A
Wyre Wynd (Southwire)	Jewett City, CT	SPP	Hydro	–	2,800	N/A	N/A
Strathmore/Russell	Russell, MA	SPP	Hydro	–	2,300	N/A	N/A
Crescent Mills (Texon)	Russell, MA	SPP	Hydro	–	1,500	N/A	N/A
James River Paper (Premoid)	West Springfield, MA	SPP	Hydro	–	1,200	N/A	N/A
Monadnock Paper Mills	Bennington, NH	SPP	Hydro	–	2,145	N/A	N/A
James River Hydro	Ber/Gor/Shelb, NH	SPP	Hydro	–	27,244	N/A	N/A
				SUBTOTAL	79,139	0	0
				TOTAL	721,586	635,610	598,250

(1) "SPP" Denotes a Small Power Producer, "COGEN" Denotes a Cogenerator.

(2) Estimated Capacity Represents Contracted/Rate Order Capacity.

(3) Estimated Capacity Represents Estimated Installed Capacity.

ENCLOSURE 2

UPDATED PROFILES

- o B. M. Fox
- o J. F. Opeka
- o T. C. Feigenbaum

PEOPLE PROFILE

NORTHEAST UTILITIES

P.O. Box 270
Hartford, Connecticut 06141-0270

BERNARD M. FOX

Bernard M. Fox is president and chief executive officer of Northeast Utilities (NU).*

He is also a trustee of NU and president and chief executive officer and a director of the Connecticut Yankee Atomic Power Company.

Born in New York City, ***Fox*** was graduated from Regis High School in 1959, Manhattan College in 1963 with a bachelor of science degree in electrical engineering and in 1964 from Rensselaer Polytechnic Institute with a master's degree in the same discipline. In 1979, ***Fox*** completed the Program for Management Development at the Harvard Business School. In 1982, he completed a special program of study in auditing, legal affairs and financing activities, including a three-month assignment with Morgan Stanley and Company in New York City.

Fox joined The Hartford Electric Light Company (HELCO) in 1964 as a cadet engineer. In 1966, after HELCO had become a subsidiary of NU, he was named an engineer in NU's System Planning Department, and senior engineer in 1971. He transferred to the utility's Nuclear Engineering and Operations group in 1973. In 1979, he was appointed system director—Engineering Management Services, and system director—Transmission Engineering and Construction in 1980. He was appointed to the post of vice president and general manager Gas in 1981 and was elected to the position of vice president and chief financial officer in 1983. In 1986 he was elected executive vice president and chief operating and financial officer. In 1987 he became president and chief operating and financial officer, and relinquished the position of chief financial officer in 1990. He assumed his present position in 1993.

Fox is chairman of the board of the Institute of Living. He also serves on the board of directors of Shawmut Bank Connecticut, N.A., Shawmut Bank, N.A., and Shawmut National Corp., Dexter Corporation, the Connecticut Business and Industry Association, and GroupAmerica, a subsidiary of CM Alliance Companies. In addition, he is a member of The Mount Holyoke College Board of Trustees, a member of the Board of the 1995 Special Olympics World Summer Games organization, a member of The Hispanic Health Council's Capital Campaign Fundraising Committee, Dinner Chairman of the 1994 Manhattan College De La Salle Medal Dinner, Chairman of the Fidelco 1994 Walk-Run-Ride Event, and Ticket Sales Chairman of the 1994 Girl Scouts Woman of Merit Dinner. He is a senior member of the Institute of Electrical and Electronics Engineers (IEEE) and has held a number of IEEE state and national offices. In addition, he served as chairman of Leadership Greater Hartford from 1988-91, chairman of the Connecticut Special Olympics Hartford Corporate Advisory Committee from 1988-91, chairman of the 1992 United Way of the Capital Area Campaign, and is past chairman of the Open Hearth Capital Campaign. He is a fellow and founder of the American Leadership Forum and has taught graduate courses in electrical power systems analysis and related fields as an adjunct professor at the University of Connecticut.

Fox and his wife Marilyn have three children and live in Avon, Connecticut.

** NU is a registered holding company formed in 1966 whose principal operating company subsidiaries are The Connecticut Light and Power Company, Holyoke Water Power Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company, and whose principal nonoperating subsidiaries are North Atlantic Energy Corporation, North Atlantic Energy Service Corporation, Northeast Nuclear Energy Company, and Northeast Utilities Service Company. In addition, Charter Oak Energy, Inc., and HEC Inc., are NU's nonutility subsidiaries.*

October 1993

PEOPLE PROFILE

NORTHEAST UTILITIES
P.O. Box 270
Hartford, Connecticut 06141-0270

JOHN F. OPEKA

John F. Opeka is executive vice president--Nuclear for Northeast Utilities (NU).* He is responsible for overall technical support and operation of NU's nuclear facilities.

A native of Forest City, Pennsylvania, ***Opeka*** received a bachelor of science degree in electrical engineering from Pennsylvania State University and a master's degree in business administration from Rensselaer Polytechnic Institute at the Hartford Graduate Center. He also completed the Program for Management Development course at the Harvard Business School. He served in the United States Navy from 1962 to 196

Opeka began his utility career with NU in 1970 as an engineer in the Nuclear Production Department at Berlin. He was assigned to the company's Millstone Nuclear Power Station in that capacity in 1972 and was made senior engineer there in 1973. He obtained a senior reactor operator's license in 1975 and later that year was named Millstone plant services superintendent. In 1977 he became assistant station superintendent and was named station superintendent in 1978. In this position, ***Opeka*** was responsible for the overall operation and maintenance of Millstone Units 1 and 2. He was named system superintendent--Nuclear Operations, in 1980, becoming responsible for the overall operation and maintenance of both Millstone units and the Connecticut Yankee nuclear plant. He was elected vice president--Nuclear Operations in June 1981, was named senior vice president--Nuclear Engineering and Operations in 1985, and executive vice president of Engineering and Operations in 1986. He assumed his present position in November 1991.

He is a member of the American Nuclear Society and the Pennsylvania State University's Alumni Association, and is a fellow of the American Leadership Forum. He is also on the board of directors for the Opportunities Industrialization Center of New London County and on the board of trustees for the Thames Science Center.

Opeka and his wife Jacqueline have two daughters and live in Old Lyme, Connecticut.

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