# ABBREVIATED VERSION

## COMPLETE COPY FILED ELECTRONICALLY
## (April 30, 2009 – DE 06-015)

### 2003 LONG RANGE PLAN

### VOLUME I

**FOR**

**NEW HAMPSHIRE ELECTRIC COOPERATIVE**


**Principal Contributors:**

Thomas F. Bartel
Peter A. Daly
Dennis R. Eicher
Duane T. Kexel
Dennis M. Levy
Gregory L. Shirek
William L. Stroess

**Respectfully Submitted,**

Power System Engineering, Inc.
2000 Engel Street
Madison, WI 53713
Phone: 608-222-8400
Fax: 608-222-9378


October 21, 2003

# Table of Contents

# List of Tables



# List of Figures



# Exhibits



# Appendix

# ES Executive Summary

## Introduction

This report presents the results of an engineering study focused on planning the key electric system additions, changes and upgrades New Hampshire Electric Cooperative (NHEC) should complete during the next 20 years to provide an acceptable level of high quality service to its members.

The study started with a review of NHEC's existing system performance to provide a foundation for the Long Range Plan. Future loads were forecast for each substation, circuit and metering point to determine how much power each circuit will need to deliver 20 years into the future.

Planning criteria were developed for transmission and distribution system performance. NHEC's power delivery system includes 34.5 kV subtransmission lines, distribution substations and distribution lines operating at voltages ranging from 4.16-34.5 kV. The criteria specify that the system must supply adequate voltage to the members under all expected load levels and that all system components must be sized large enough so they will not fail during high load conditions.

Electric service reliability has become more important to members because they have advanced appliances and other types of electric powered equipment that support their daily activities. Reliability criteria were established for this study to help identify underperforming system segments and develop recommendations for improvement.

# Load Forecast

System loads are expected to increase in some areas and remain stable in others. Relatively high growth rates are expected in the Alton, Meredith, Ossipee, Plymouth and Raymond areas. Very low or no growth is expected in the Andover, Colebrook, Conway, Lisbon and Sunapee areas. The load forecast methodology is discussed in Section 3.0, and the forecast results are presented for each district starting with Alton in Section 6.0.

This planning study relies centrally on load forecasts that have been developed from the bottom-up at the delivery point level. The methodology used was made possible by NHEC's ability to provide consumer by town data for each delivery point for the past two years. This allowed calculation of consumer-population ratios (CPRs) which were combined with demand per consumer (DPCs) to yield the load forecast for each delivery point. This approach provided each NHEC District Manager a clear forecasting framework and allowed PSE to get critical local input to the forecast. All forecasting methods become stronger over time as the forecasts are tracked against actual data and methods are adapted to reduce forecast errors. PSE strongly recommends that the delivery point tables provided in this study be regularly (preferably annually) updated as a guide to improvement of the small area forecasts. The next system wide forecast should also reconcile the differences observed between the demand data used in the 1999 NHEC load forecast and the sum of delivery point loads used for this study.

# Transmission Plan

PSE worked extensively with Public Service of New Hampshire (PSNH) in developing transmission system models focused on serving NHEC's requirements. PSNH inserted the Long Range load projections into their data base and completed system performance calculations for PSE review. Table E-1 Summarizes the proposed PSNH and NHEC projects that will keep the transmission supply adequate for the loads expected through 2023. The proposed NHEC transmission projects are shown in Figures E-1 and E-2. Sections 6-15 present the transmission study results for each district.

## Table E-1 Summary of Proposed PSNH and NHEC Transmission Projects

| DISTRICT | PSNH DESIGN CRITERIA REQUIRED PROJECT | PSNH OPTIONAL PROJECT TO PROVIDE CONTINGENT CAPABILITY - NOT REQUIRED | NHEC ENHANCED RELIABILITY/CONTINGENT CAPACITY PROJECT | |
|---|---|---|---|---|
| ALTON | PSNH developing a fourth Rochester 34.5 kV feeder in 2004 | Upgrade PSNH transformer capacity at Rochester in 2020, add an additional 34.5 kV feeder exit at PSNH's Dover Substation in 2022 and develop a fourth Rochester 34.5 kV feeder in 2004. PSNH needs to reconductor Madbury 3137 feeder from 266 MCM ACSR to larger conductor between VSH 4 and USH 125 and add a capacitor bank to support this backup in 2003. Also need to add a second trasnformer to Oak Hill in 2004 . | 1. Portland Street - N. Rochester, feeder 385, 4.68 miles, upgrade 1/0, 4/0 and 477 MCM ACSR to all 477 MCM ACSR. (Project TM-4) | $604,000 |
| | | | 2. N. Rochester - Farmington, Feeder 362, 4.15 miles, upgrade 1/0, 4/0 and 477 MCM ACSR to all 477 MCM ACSR. (Project TM-5) | $535,000 |
| | | | 3. Farmington - New Durham, New Feeder, 5 miles of 477 MCM ACSR. (Project TM-6) | $630,000 |
| | | | 4. New Durham - Alton, New Feeder, 4.3 miles of 477 MCM ACSR. (Project TM-7) | $504,000 |
| | | | 5. Six 34.5 kV recloser/Sectionalizer with local and remote SCADA control | $210,000 |
| | | | TOTAL | $2,483,000 |
| ANDOVER | Webster-Laconia: Second Webster to Laconia 115 kV Circuit - 2003 | | | |
| | Webster-Laconia: Rebuild Webster-Laconia 337 34.5 kV feeder -2003 | | | |
| | Pemigewasett Substation: Increase 115-34.5 kV transformer - 2005 | | | |
| | Ashland Substation: Increase 115-34.5 kV trasnformer - 2005 | | | |
| COLEBROOK | PSNH will add a 34.5 kV 1.2 MVAR capacitor bank to PSNH Feeder 355 near Colebrook Substation in 2013 | | | |
| CONWAY | | | Additional banks at Jackson, 1.8 MVARs; Glen, 0.6 MVARs; and Bartlett, 0.6 MVARs | $45,000 |
| LISBON | On the load side of the Sugar Hill voltage regulator station, PSNH will add a 1.4 MVAR capacitor bank | | | |
| MEREDITH | In 2005, PSNH plans to upgrade the 115-34.5 kV transformers at both Ashland and Pemigewasett Substations. PSNH will also reconfigure the Straights Switching Station to permit Meredith 2 to be served by the Pemigewasett 345 feeder. PSNH maintain Unity Power Factor at PSNH 34.5 kV delivery points | | NHEC distribution voltage capacitor banks - 3.6 MVARs - 2004 | $75,000 |
| | | | NHEC maintain Unity Power Factor at 34.5 kV delivery points - Meredith I, Center Harbor and Melvin Village - 2005-2023 | $100,000 |
| OSSIPEE | PSNH plans to reconductor White Lake feeder 346 from Ossippee to Tuftonboro by the 2005 summer. PSNH will first add capaciors and then extend 34.5 kV White Lake feeder 3116 from Center Ossippee to Tuftonboro and install an additional regulator station at Tuftonboro on feeder 3116. In 2117, PSNH will increase the capacity of the Tuftonboro regulators on feeder 346. In 2119, PSNH will extend an additional 34.5 kV line from Tuftonboro to Wolfboro. | | | |
| PLYMOUTH | PSNH plans to upgrade the capacity of the Ashland 15 - 34.5 transformer in 2005. | | New Beebe River - Thornton 34.5 kV feeder - 2004. (Project TM-1) | $620,000 |
| | | | New N. Woodstock 34.5 kV feeder to NHEC's Lincoln Substation - 2004 (Project TM-2) | $960,000 |
| | | | Rebuild PSNH's Holderness 34.5 kV Switching Station. (Project TM-3) | $150,000 |
| | | | Waterville Valley and Thornton Substations 3.6 MVARs line capacitors - 2004 | $75,000 |
| | | | Lincoln and Woodstock - 1.8 MVARS line capacitors - 2004 | $50,000 |
| | | | TOTAL | $ 1,855,000 |
| RAYMOND | 2004 - Chester Substation - Add a second 51/63 MVA 115-34.5 kV transformer | | | |
| | 2005 - Brentwood Substation (proposed) - Develop new 15 - 34.5 kV sub with 1-44 MVA transformer and 3 feeders | | | |
| | 2006 - Mammoth Road Substation - Add a second 57/62 MVA 115-34.5 kV transformer | | | |
| | 2010 - Brentwood Substation to Raymond Substation - Develop new 11 mile 34.5 kV feeder | | | |
| | 2017 - Brentwood Substation - Add a second 44 MVA transformer | | | |
| SUNAPEE | NO WORK NEEDED | | | |

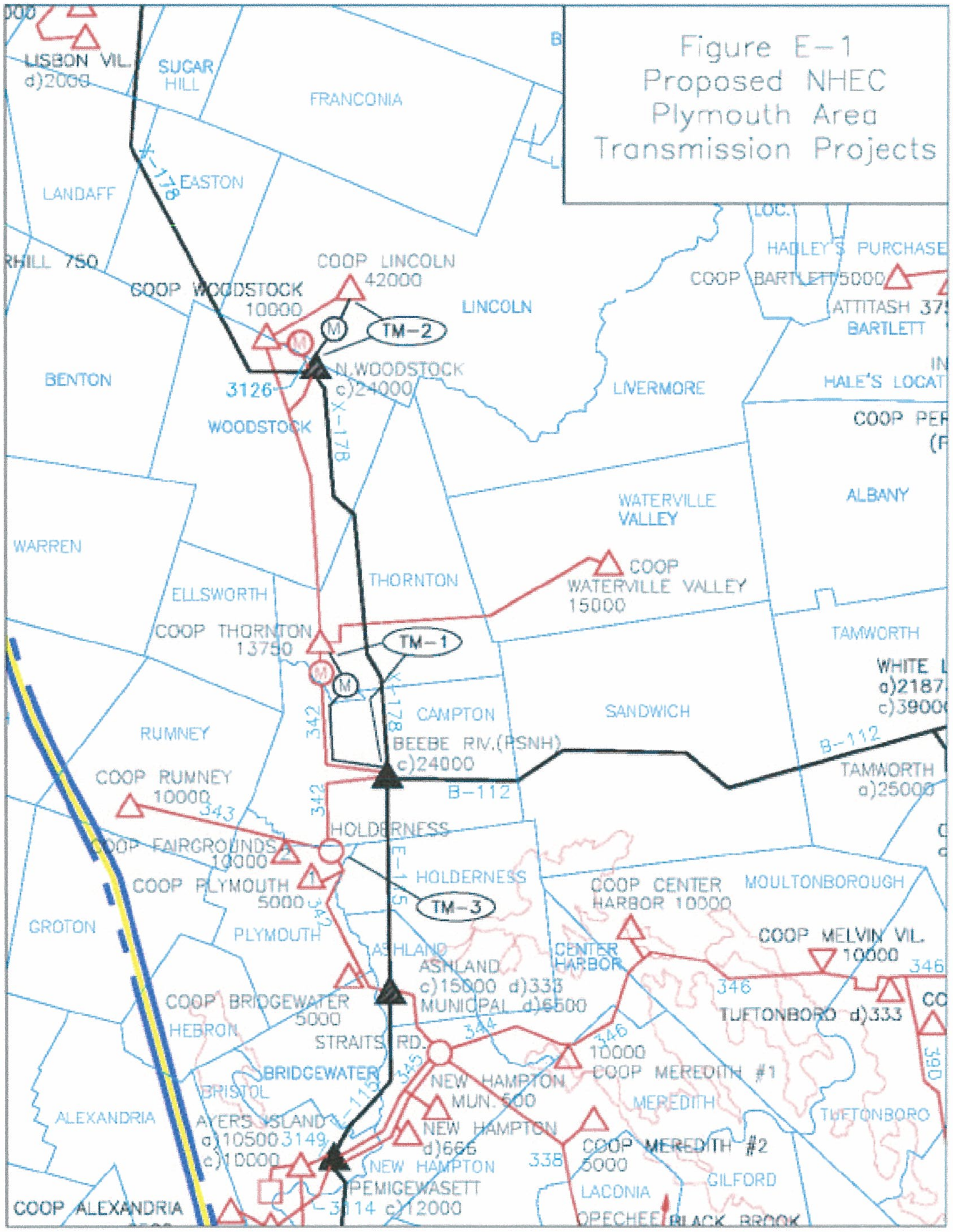



**Figure E-1 Proposed NHEC Plymouth Area Trnasmission Projects**

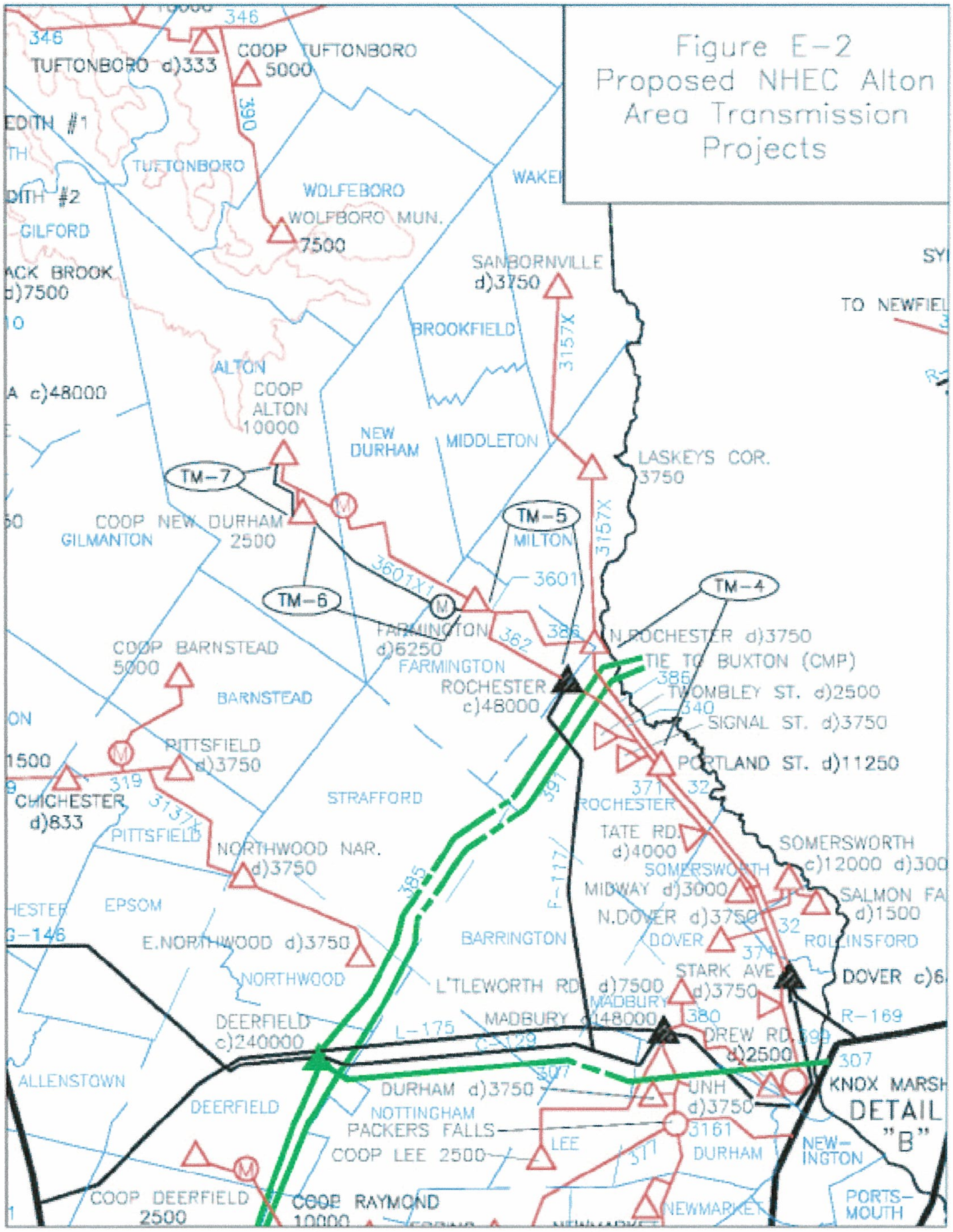



**Figure E-2 Proposed NHEC Alton Area Trnasmission Projects**

## Distribution Plan

The proposed Plan includes five new distribution substations and metering points, which are summarized in Table E-2. Sections 6-15 present the detailed discussion and cost estimates for these proposed projects.

**Table E-2 Summary of Proposed New Distribution Substations and Delivery Points**

| District | Proposed Location | Planning Period |
|---|---|---|
| Alton | Belmont East Delivery Point | 2004-08 |
| Andover | Wilmont Substation | 2009-13 |
| Conway | Intervale Substation | 2004-08 |
| Meredith | Moultonborough Substation | 2009-13 |
| Sunapee | East Lempster Delivery Point | 2004-08 |

The proposed distribution line additions and changes are presented in Sections 6-15. There is a variety of projects proposed for each district, which are summarized in the cost tables at the end of each section. Table E-3 presents a high level summary of the distribution system improvements (substations, delivery points and lines) included in the proposed Plan.

**Table E-3 Proposed Distribution Project Cost Summary**

| District | Substations/ Delivery Points | Line Additions and Changes | Total |
|---|---|---|---|
| Alton | 520,000 | 2,636,000 | 3,156,000 |
| Andover | 840,000 | 1,312,000 | 2,152,000 |
| Colebrook | 109,000 | 338,000 | 447,000 |
| Conway | 678,000 | 1,657,000 | 2,335,000 |
| Lisbon | 120,000 | 265,000 | 385,000 |
| Meredith | 916,000 | 4,205,000 | 5,121,000 |
| Ossipee | 120,000 | 833,000 | 953,000 |
| Plymouth | 1,015,000 | 4,677,000 | 5,692,000 |
| Raymond | 256,000 | 2,539,000 | 2,795,000 |
| Sunapee | 246,000 | 3,695,000 | 3,941,000 |
| TOTAL | 4,820,000 | 22,157,000 | 26,977,000 |

## Reliability Analysis

PSE analyzed NHEC's reliability data from the past three years to identify where extra effort should be applied to address poor performing circuits. The Intervale 34.5 kV transmission circuit owned by NHEC in the Conway district has experienced a significant number of tree related outages during 2002 which should be reviewed for possible corrective action. All other transmission circuits appear to be operating within the planning criteria.

Figure E-3 shows the past three year System Average Interruption Duration Index (SAIDI) for each NHEC distribution feeder. The figure has the feeders ranked from worst to best. The worst performing circuit was LY12 (LYME Circuit 12 in the Plymouth district) with 15.6 hours of interruption per year. The best performing circuit was WV24 (Water Valley Circuit 24 in the Plymouth District) with no outages. We suggest that NHEC focus on improving the reliability of its ten worst circuits during 2004. Sections 6-15 discuss the causes for the interruptions along with initial recommendations for improvement. NHEC should complete field inspections of the ten worst circuits to gain a better understanding about why they do not perform well. Then NHEC should develop specific improvement plans for each circuit and follow through on implementation until the desired results are achieved.

Figure E-4 shows the past three year System Average Interruption Frequency Index (SAIFI) for each NHEC distribution feeder. This figure shows how often each circuit has an interruption each year. It is interesting to note that most of the circuits with high total outage times also have the highest number of interruptions per year.

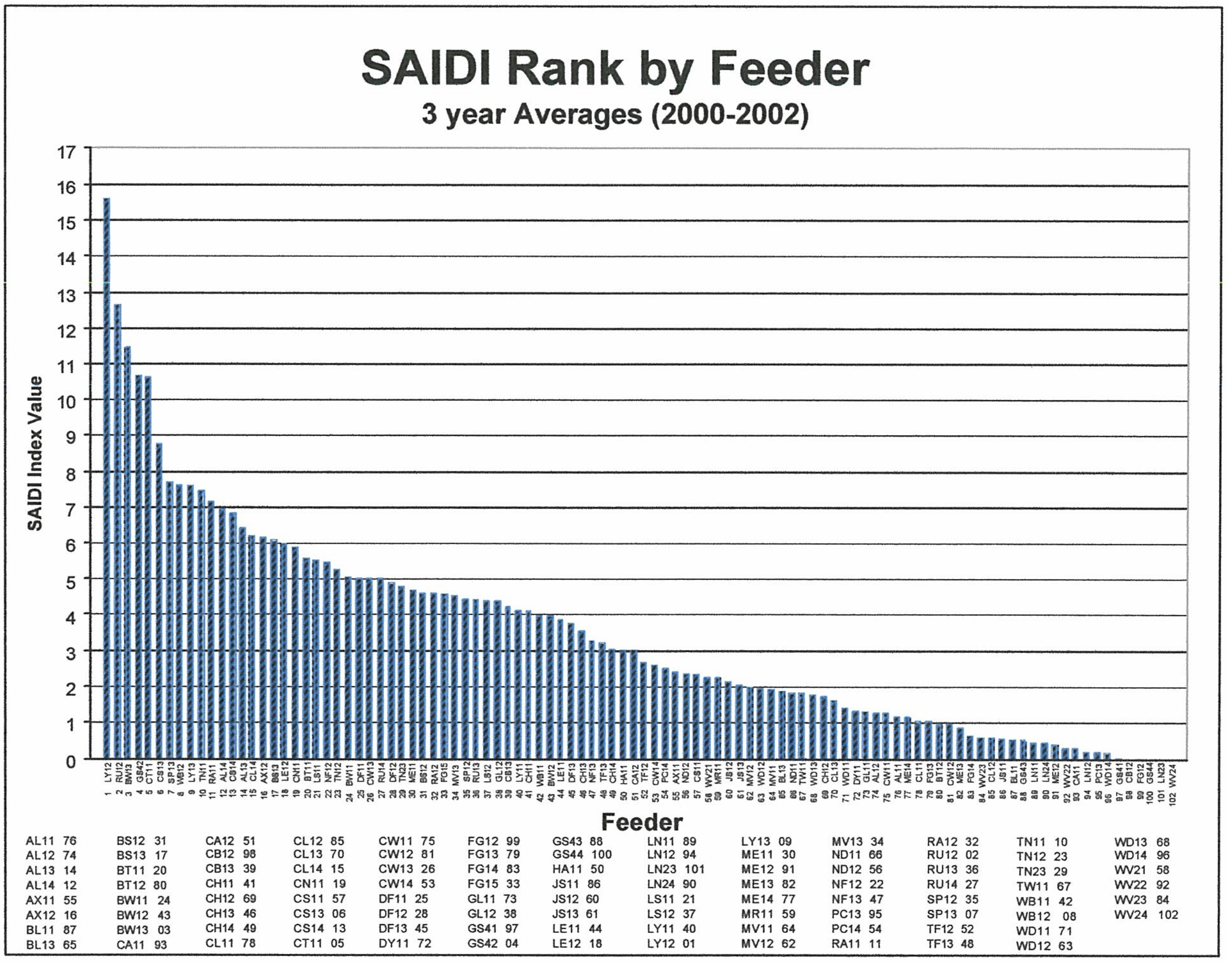
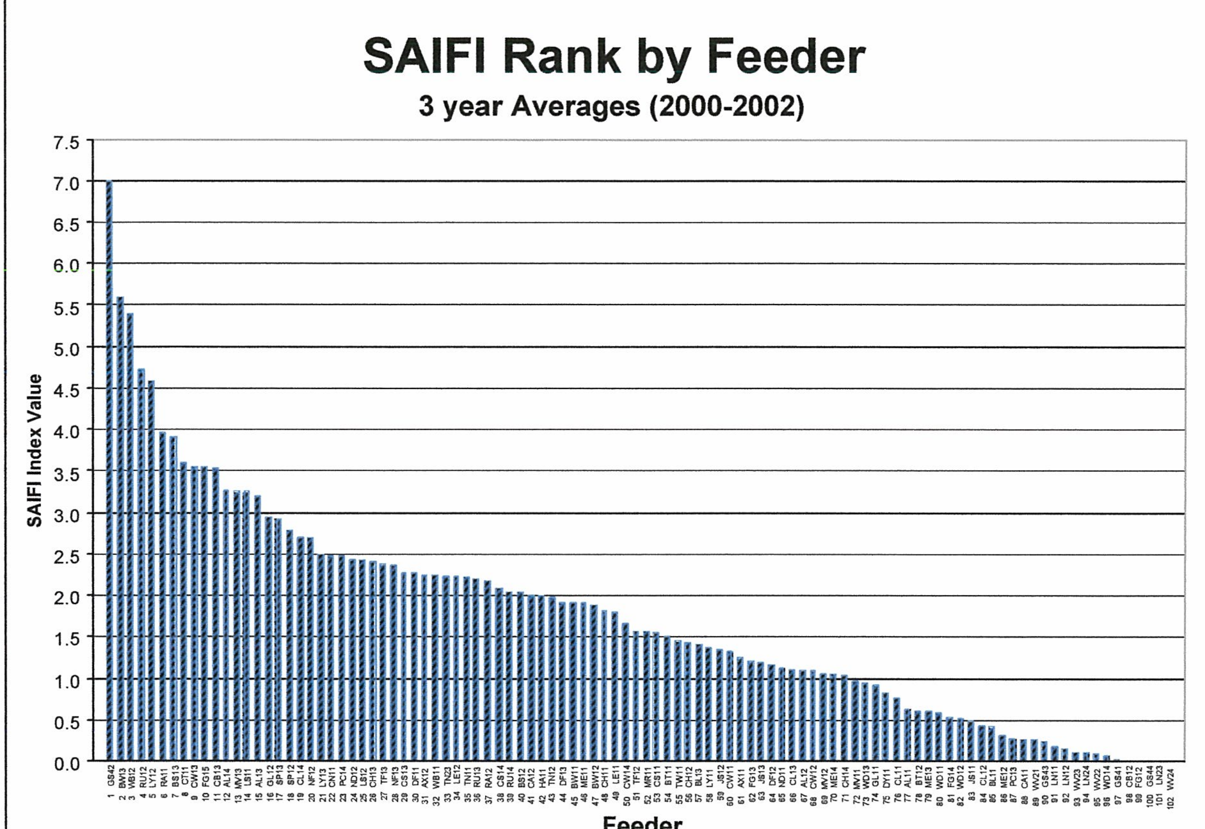



**Figure E-3 SAIDI Rank by Feeder**




| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AL11 77 | BS12 40 | CA12 41 | CL12 84 | CW11 60 | FG12 99 | GS43 90 | LN11 91 | LY13 21 | MV13 13 | RA12 37 | TN11 35 | WD13 73 |
| AL12 67 | BS13 07 | CB12 98 | CL13 66 | CW12 68 | FG13 62 | GS44 100 | LN12 92 | ME11 46 | ND11 65 | RU12 04 | TN12 43 | WD14 96 |
| AL13 15 | BT11 54 | CB13 11 | CL14 19 | CW13 09 | FG14 81 | HA11 42 | LN23 101 | ME12 86 | ND12 24 | RU13 36 | TN23 33 | WV21 89 |
| AL14 12 | BT12 78 | CH11 48 | CN11 22 | CW14 50 | FG15 10 | JS11 83 | LN24 94 | ME13 79 | NF12 20 | RU14 39 | TW11 55 | WV22 95 |
| AX11 61 | BW11 45 | CH12 56 | CS11 53 | DF11 30 | GL11 74 | JS12 59 | LS11 14 | ME14 70 | NF13 28 | SP12 18 | WB11 32 | WV23 93 |
| AX12 31 | BW12 47 | CH13 26 | CS13 29 | DF12 64 | GL12 16 | JS13 63 | LS12 25 | MR11 52 | PC13 87 | SP13 17 | WB12 03 | WV24 102 |
| BL11 85 | BW13 02 | CH14 71 | CS14 38 | DF13 44 | GS41 97 | LE11 49 | LY11 58 | MV11 72 | PC14 23 | TF12 51 | WD11 80 | |
| BL13 57 | CA11 88 | CL11 76 | CT11 08 | DY11 75 | GS42 01 | LE12 34 | LY12 05 | MV12 69 | RA11 06 | TF13 27 | WD12 82 | |

**Figure E-4 SAIFI Rank by Feeder**

# Distributed Generation

Some utilities have used distributed generation to provide improved reliability and defer system construction. The economics associated with distributed generator applications can be quite sensitive to the actual characteristics of each specific case. PSE has developed three example cases (summarized in Appendix A) for NHEC consideration that are based on current costs. The methodology shown in the examples can be used to evaluate other cases that may develop in the future.

# Closing

This report should provide a valuable guide for future system development as well as a useful tool in planning future financial requirements. Construction of facilities proposed in this study should be undertaken on the basis of recommendations in future Construction Work Plans in order to recognize conditions as they actually develop. In this manner, the planning report should continue to provide overall coordination for system development, even though local changes in load growth or system conditions may require some departure from the plans proposed in this study.

# 1.0 Introduction

## 1.1 Scope

This report presents the results of an engineering study to determine the twenty year transmission and distribution (T&D) system requirements of New Hampshire Electric Cooperative (NHEC or the Cooperative). The study establishes proposed 5-Year, 10-Year and 20-Year Plans which provide an engineering outline for the orderly development of the transmission and distribution system to accommodate load growth, improve reliability and to replace lines that are expected to reach the end of their useful life within the study period.

Section 2.0 provides a review of the Cooperative's system as it exists today. This includes a review and/or assessment of the Cooperative's power supply arrangements, transmission system and distribution system. The performance review addresses such topics as voltage and current measurements, reliability, contingency arrangements, power factor and losses.

Section 3.0 provides an analysis of the Cooperative's historical and projected loads for the system as a whole for each of the Cooperative's 10 districts. In Sections 6.0 through 15.0, we address the district load forecasts by area based on historical load growth, population projections, and land use along with the results of discussions with the Cooperative's District Managers.

Section 4.0 provides a discussion of the planning criteria used in this study, including voltage and current limits, reliability and economics as applied to the transmission and distribution system. We paid special attention in this study to designing a system that would enhance reliability by decreasing both the number and duration of outages.

Section 5.0 provides a discussion of the procedures and approaches used to prepare the Long Rang Plan.

Sections 6.0 - 15.0 present the analysis of the system at the 5-Year, 10-Year and 20-year levels. We present the analysis on a district-by-district basis and include a discussion of the small area forecasts, identification of performance and/or reliability problems, identification of alternative solutions, evaluation of alternatives and development of a recommended plan.

It is important to emphasize that the plans proposed in this report are intended to be used as a general guide for system development. Since actual load growth in the future and other factors affecting system development may vary from the parameters and assumptions used in this study, periodic review and possible modification of the plans may be required. Actual construction, therefore, should be based on recommendations resulting from subsequent Construction Work Plans. Used in this fashion, adherence to the proposed Long Range Plan should permit maximum utilization of existing facilities and orderly expansion of new facilities to address load growth, reliability, and system aging.

## 1.2 Reference Material

The following reports were referred to in the preparation of this study.

- *2001-2005 Construction Work Plan*; New Hampshire Electric Cooperative; September 2001.
- *1997-1999 Construction Work Plan*; Electrical Systems Consultants, October 1996.
- *Long Rang Planning Report*; Electrical Systems Consultants, January 1991.

# 2.0 Existing System Review

## 2.1 Overview

New Hampshire Electric Cooperative is a rural electric cooperative with headquarters located in Plymouth, New Hampshire. The service territory is mostly rural and covers about 30 percent of New Hampshire's geographic area. Parts of the service area approach the borders of Vermont, Maine, Massachusetts and Canada. The geography ranges from coastal low lands in the Southeast to forests and mountains in the north.

An overview of key existing system data is presented in the following table, with details and implications of the existing system being discussed in later sections of this study.

**Table 2-1 Overview of Existing System Data**

| | |
|---|---|
| Winter Non-Coincident System Peak Demand | 161 MW |
| Summer Non-Coincident Peak Demand | 111 MW |
| Average Monthly Residential usage | 525 kWh |
| Annual Energy Purchases | 640 MWH |
| Annual Energy Sales | 596 MWH |
| KWh Load growth from 1989 to 2002 | 5.6 % |

NHEC serves approximately 73,000 consumers, with the residential class accounting for approximately 60 percent of NHEC's total energy sales. The commercial class accounts for about 35 percent and large ski areas about 5 percent.

The NHEC service territory is divided into 10 Operating Districts. District offices are located in the cities of Alton, Andover, Colebrook, Conway, Lisbon, Meredith, Ossipee, Plymouth, Raymond and Sunapee. A map showing the general boundaries of the service area and offices within each district operation is presented in the following figure.

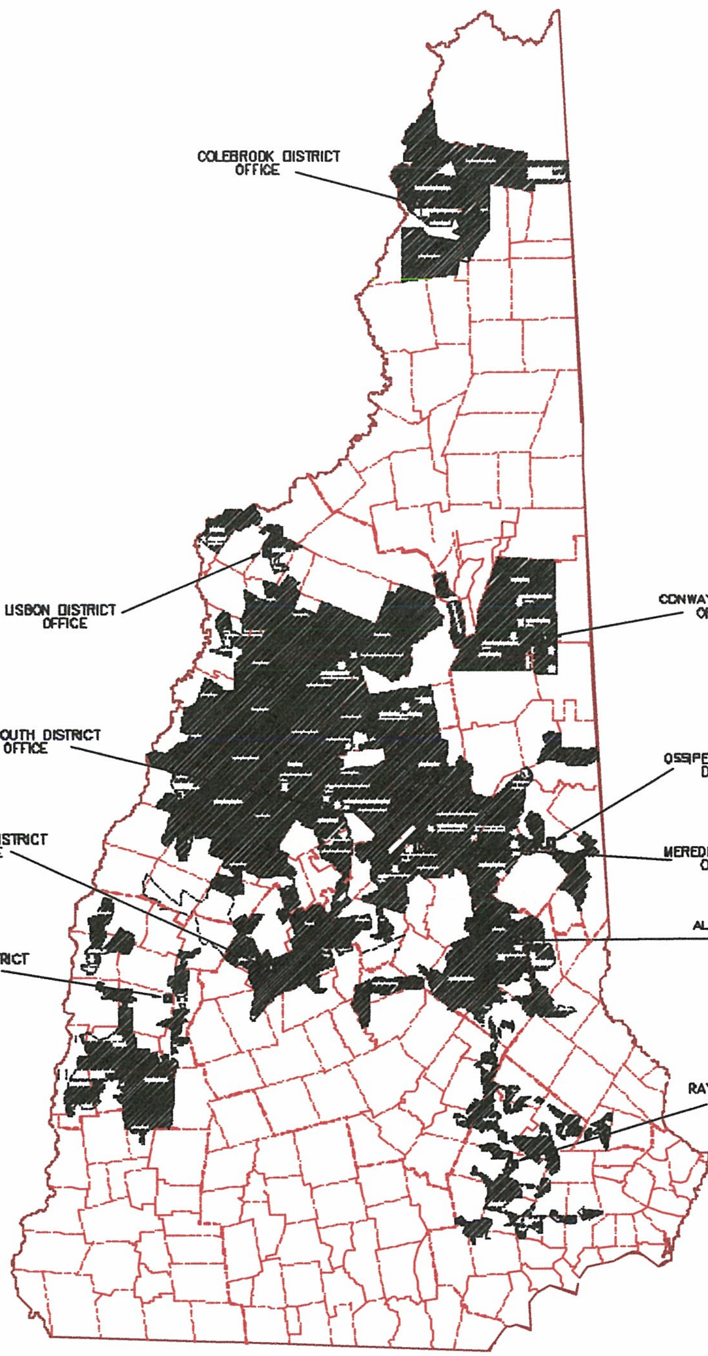



**Figure 2-1 NHEC Service Area**

## 2.2 Power Supply

Energy is delivered to NHEC's distribution substations and meter points primarily by 34.5 kV subtransmission lines and also at 115 kV. Historically, NHEC's largest power supplier has been Public Service Company of New Hampshire (PSNH), with lesser amounts supplied by Central Vermont Public Service (CVPS), New England Power Company (NEP), and Green Mountain Power Company (GMP). Retail competition in New Hampshire has changed this situation, such that NHEC is no longer obligated to purchase and supply its power and energy requirements from these four power suppliers. Nevertheless, it is still useful and accurate to refer to each of these areas using their historical power supplier name, since they each tend to have distinct power supply arrangements. The breakdown of theses suppliers and their contribution to NHEC's total system demand for 2002 is seen below.

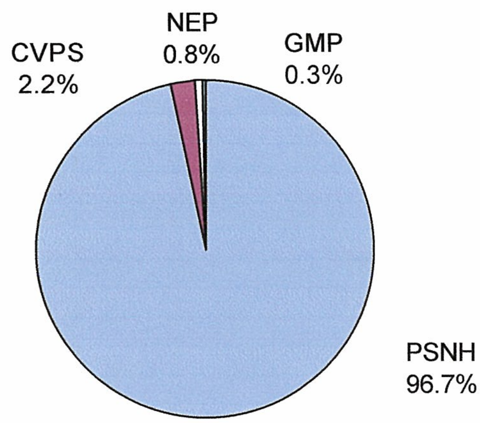



**Figure 2-2 2002 NHEC Energy Requirements as Percent of Total Energy Requirements**

The transmission system in New Hampshire is jointly planned and operated under the auspices of the Independent System Operator-New England (ISO-NE) to the North American Electric Reliability Council (NERC), New England Coordinating Council (NPCC), and ISO-NE standards. Ownership of new transmission lines and facilities occurs under the open market rules promulgated by the Federal Energy Regulatory Commission (FERC); and pricing is based on the principle of locational marginal pricing (LMP)[1]. Currently, the greatest prices exist at New Hampshire's southern border, and the least at New Hampshire's interface to Maine. Because of inadequate transmission capacity, certain 115 kV lines are operated open on the interface to CMP. This limits large power flows and contingency overloads in New Hampshire due to potentially large power transfer south from Maine to the Boston Metropolitan area.

[1] Locational Marginal Pricing (LMP) is often called "nodal pricing" because LMP develops a wholesale energy price for each location or "node" on the electric power grid. The nodal price is the cost of power delivered to that grid node and reflects the cost of generation and transmission system congestion and bottlenecks. Nodal pricing is an effort to balance supply and demand using market based pricing of energy.

PSNH supplies the bulk of NHEC's power requirements through an extensive network of 34.5 kV lines. In accordance with its interpretation of FERC's "Seven Part Test,"[2] PSNH refers to its 34.5 kV system as a distribution voltage. The 34.5 kV system is operated in a network, looped and radial manner in approximately equal shares to serve NHEC delivery points.

A detailed discussion of transmission system deficiencies and recommendations is provided in the district sections of this report.

## 2.3 Transmission/Subtransmission System

The bulk power requirements of NHEC are delivered over the interconnected Northeast transmission system network. This sophisticated network connects generation stations to substations that distribute electricity to customers. This transmission system is designed and operated to deliver large quantities of electricity reliably, safely, and economically. The North American Electric Reliability Council (NERC) actively promotes the reliability of the interconnected bulk power systems in North America and in the Northeast through the Northeast Power Coordinating Regional Council (NPCC). The NPCC promotes reliability though the establishment of criteria, coordination of system planning, design and operations, and assessment of compliance with these criteria. NPCC criteria are in some cases more stringent than NERC's, but never less. The Independent System Operator-New England (ISO-NE) has the authority to manage and control New England's bulk power system. The New England Power Pool (NEPOOL) establishes the planning and operating standards by which the ISO-NE operates.

In New Hampshire, the transmission system is composed of AC lines and substations operating at nominal voltages of 345, 230, 115, 69, and 34.5 kV (subtransmission), and 450 kV DC. Public Service Company of New Hampshire (PSNH) and New England Power Company own and operate the majority of the transmission system in New Hampshire. NHEC and Central Maine Power Company (CMP) also own and operate a limited amount of transmission facilities.

PSNH provides the bulk of NHEC's power requirements at the 34.5 kV voltage level, although NHEC does take delivery at 115 kV at its Intervale Substation. For regulatory classification purposes PSNH has defined all facilities operating at 34.5 kV and lower as distribution facilities and those operating at greater voltages to be transmission. NHEC has classified all plant operating at 34.5 kV and above to be transmission. In this report, the 34.5 kV system will be

---

[2] The Federal Energy Regulatory Commission (FERC) in FERC Order 888 defined a seven-part test for the definition of distribution.

1. *Local distribution facilities are normally in close proximity to retail customers.*
2. *Local distribution facilities are primarily radial in character.*
3. *Power flows into local distribution systems; it rarely if ever flows out.*
4. *When power enters a local distribution system, it is not reconsigned or transported on to other markets.*
5. *Power entering a local distribution system is consumed in a comparatively restricted geographical area.*
6. *Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.*
7. *Local distribution systems will be of reduced voltage.*

referred to universally as the "subtransmission system" irrespective of ownership of the facilities in order to facilitate communication.

The PSNH 34.5 kV system supplying NHEC is configured in network, looped, and radial arrangement. The performance of this system on a number of outages per calendar basis is generally adequate. Outage durations, however, because of capacity constraints in the 34.5 kV system and the supplying 115 kV system, are longer than most other parts of the country. This may be due to investment capital rationing that drove the relaxation of first contingency design standards, as a result of the bankruptcy of PSNH in the mid-1980s and the Seabrook Nuclear Power Plant Project. In the place of a first contingency design standard, PSNH has adopted the "24 hour service restoration standard" which requires service to be restored in 24 hours and if necessary by the use of mobile substation equipment.

The relatively high retail rates, which resulted from this bankruptcy, have had the effect of limiting load growth and thereby limiting the near term effects of not planning to first contingency design standards at 34.5 kV. Strong economic growth in the late 1990s and increasing wholesale marginal costs in New England however have resulted in select areas of strong load growth in both PSNH's and NHEC's service areas putting pressure on the 34.5 kV PSNH facilities serving these areas.

These growth conditions have resulted in a number of areas exceeding the relaxed PSNH design criteria and where existing 34.5 kV capacity will be exceeded over the long range planning period. In other areas of the PSNH 34.5 kV network, relatively high rates have resulted in major paper mills permanently closing that resulted in a much improved system capacity margin for NHEC loads. It is important to point out that while PSNH has lowered its design criteria, NHEC has maintained its first contingency design criteria for its small part of the 34.5 kV system it owns.

Finally, as a result of the Public Utilities Regulatory Policy Act (PURPA) which required the payment of "avoided cost" based rates and PSNH's financial difficulties in the mid-1980s, PSNH has a number of 20-year contracts with significant, 5-20 MW, "small power producers" (SPP). These contracts will be expiring over the next five years and renegotiated market based rates will be much less. These generators provide significant support to the PSNH 34.5 kV network and their loss may impact load serving capability on the PSNH 34.5 kV system. Anticipating these circumstances and potentially job losses, the New Hampshire legislature has drafted a bill that is being proposed to provide financial incentives for these SPPs to continue in long term operation.

## 2.4 Distribution System

### 2.4.1 Description

The distribution system consists of approximately 5,000 miles of overhead line and 400 miles of underground line. The distribution operating voltage is primarily 7.2/12.47kV with some 2.4 kV, 14.4/24.9 kV and 19.9/34.5 kV in limited areas.

NHEC owns each of the 32 distribution substations and 12 meter points. Meter points can be directly off the 34.5 kV subtransmission lines or distribution voltage lines of other utilities. The following table lists the service points (delivery points) and the corresponding substations and metering points served by the delivery points.

**Table 2-2 Delivery Points, Substations, and Metering Points by District**

| District | Delivery Point (DP) | Substation | Metering Point (MP) |
|---|---|---|---|
| Alton | New Durham | Alton | |
| | | New Durham | |
| | Pittsfield | Barnstead | |
| Andover | Alexandria | | |
| | Northfield | Northfield | |
| | Franklin | Webster | |
| Colebrook | Colebrook | Colebrook | |
| Conway | Conway | Conway | |
| | | Perkins Corner | |
| | Saco | Bartlett | |
| | | Jackson | |
| | | Glen | |
| Lisbon | Haverhill | | Haverhill |
| | Lisbon | Lisbon | |
| | Monroe | | Monroe |
| Meredith | Center Harbor | Center Harbor | |
| | Meredith 2 | Corliss Hill | |
| | Melvin Village | Melvin Village | |
| | Meredith 1 | Meredith | |
| Ossipee | Tamworth | | |
| | Tuftonboro | Tuftonboro | |
| Plymouth | Bridgewater | Bridgewater | |
| | Plymouth 1 | Green Street | |
| | Plymouth 2 | Fairgrounds | |
| | Woodstock | Lincoln (3 subs) | |
| | | Woodstock | |
| | Lyme | | Lyme |
| | Rumney | Rumney | |
| | Thornton | Thornton (2 subs) | |
| | | Waterville Valley | |
| Raymond | Brentwood | | |
| | Chester | Chester | |
| | Deerfield | | |
| | Derry | | Derry |
| | Lee | | |
| | Raymond | Raymond | |
| Sunapee | Calavant | | Calavant (aka Maple Ave.& N. Charlestown |
| | Charlestown | | Charlestown |
| | Cornish | | Cornish |
| | Sunapee | Sunapee | |

Comments:
Conway DP serves two subs: Conway and Perkins corner
New Durham DP serves two subs: New Durham and Alton
Pittsfield DP serves the Barnstead substation
Saco DP serves three subs: Bartlett, Glen, and Jackson
Thornton DP serves two subs: Thornton and Waterville Valley
Woodstock DP serves two subs: Woodstock and Lincoln

### 2.4.2 System Performance

An analysis of the primary distribution system was made using the existing system configuration and the following load levels:

- 2003 – existing
- 2008 – 5 year plan
- 2013 – 10 year plan
- 2023 – 20 year plan

A Long Range Plan, Proposed System Arrangement, Circuit Diagram I, has been prepared for each district. The diagram shows the calculated voltage drops for each delivery point, substation, and metering point within the district for the 2023 load levels. An analysis was also made for the 5 and 10 year transition plans. The corresponding calculated loads by service point and circuit for the existing 2003 and forecasted 2008, 2013 and 2023 load levels are provided in the district sections of this report.

A significant portion of the main three-phase lines are built with 336 MCM or 1/0 ACSR. Largely because of this, the analysis of the existing system configuration using the 2023 load level did not identify any areas of significant primary line voltage deficiency under normal operation with all of the existing facilities in service. On the longest circuits, several areas were found where the calculated voltage drops were approaching the maximum limit near the circuit's extremities. Also, some heavily loaded single-phase lines were found in areas with concentrated loads. These areas were studied to determine the best overall plan to provide the needed capacity and improve voltage and service. A detailed discussion of potential voltage and capacity problems at the 2008, 2013 and 2023 load levels is provided in the district sections of this report along with the recommended plan.

The district contingency studies reveal only some of the existing circuits are tied to circuits of other substations with three phase lines. Even with the three-phase ties, some areas are difficult to backup because of the distance from the adjacent substation and/or small conductor lines. Also, areas that are served radial can be difficult to backup. The following table shows each circuit and indicates if the circuit is radial. These areas have been studied to determine the best method of providing improved backup. A detailed discussion of system reliability is provided in the district sections of this report along with recommendations.

**Table 2-3 Radial and Other Areas with Limited Backup Capacity**

| District | DP | Substation | Looped Circuts | Radial Circuts |
|---|---|---|---|---|
| Alton | New Durham | Alton | AL11 | AL12, AL13, AL14 |
| | | New Durham | ND12 | ND13 |
| | Pittsfield | Barnstead | | BS12, BS13 |
| Andover | Alexandria | Alexandria | | AX11, AX12 |
| | Northfield | Northfield | | NF12, NF13 |
| | Franklin | Webster | | WB11, WB12 |
| Colebrook | Colebrook | Colebrook | CB12 | CB12, CB13 |
| Conway | Conway | Conway | CW11, CW12, CW13, CW14 | |
| | | Perkins Corner | PC13, PC14 | |
| | Saco | Bartlett | BL11 | BL13 |
| | | Jackson | JS13 | JS11, JS12 |
| | | Glen | GL11-GL12 | |
| Lisbon | Haverhill | Haverhill | | HA11 |
| | Lisbon | Lisbon | | LS11, LS12 |
| | Monroe | Monroe | | MR11 |
| Meredith | Center Harbor | Center Harbor | | CH11, CH12, CH13, CH14 |
| | Meredith 1 | Meredith | ME12 | ME11, ME13, ME14 |
| | Meredith 2 | Corliss Hill | CL12 | CL11, CL13, CL14 |
| | Melvin Village | Melvin Village | | MV11, MV12, MV13 |
| Ossipee | Tamworth | Tamworth | | TW11 |
| | Tuftonboro | Tuftonboro | | TF12, TF12, TF13 |
| Plymouth | Bridgewater | Bridgewater | | BW11, BW12, BW13 |
| | Plymouth 1 | Green Street | GS41, GS43 | GS42, GS44 |
| | Plymouth 2 | Fairgrounds | FG13, FG15 | FG12, FG14 |
| | Woodstock | Lincoln (3 subs) | LN12, LN23, LN24 | LN11 |
| | | N. Woodstock (Loon) | WD13 | WD11, WD12, WD14 |
| | Lyme | Lyme | | LY11, LY12, LY13 |
| | Rumney | Rumney | RU11 | RU11, RU12, RU13 |
| | Thornton | Thornton (2 subs) | TH23 | TH11, TH12 |
| | | Waterville Valley | WV24 | WV21,WV22, WV23 |
| Raymond | Brentwood | Brentwood | | BT31 |
| | Chester | Chester | CS13 | CS11, CS14 |
| | Deerfield | Deerfield | DF11 | DF12, DF13 |
| | Derry | Derry | | DY11 |
| | Lee | Lee | LE11 | LE12 |
| | Raymond | Raymond | RA11, RA12 | |
| Sunapee | Calavant | Calavant | | CA11, CA12 |
| | Charlestown | Charlestown | | CT11 |
| | Cornish | Cornish | | CN11 |
| | Sunapee | Sunapee | | SP12, SP13 |

NHEC's reliability numbers have been greatly improved over the past several years for a number of reasons including the replacement or rebuilding of approximately 115 miles of old copperweld and/or amerductor conductor. Furthermore, methods of decreasing outage durations through the use of faulted circuit indicators and meters with outage reporting devices have been implemented.

A summary of service interruptions for the entire system is shown in the following table provided from NHEC personnel. Additional outage information is shown and discussed in the Executive Summary section of the report.

**Table 2-4 Summary of Service Interruptions**

| YEAR | QUARTER | SAIFI | SAIDI | CAIDI | ASAI | Number of Customers Interrupted | Customer Hours of Interruption | Average Number of Customers Served |
|---|---|---|---|---|---|---|---|---|
| 1996 | 1st | 0.6737 | 99.5 | 147.7 | 99.92426 | 44392 | 109297 | 65896 |
| | 2nd | 0.6547 | 64.6 | 98.7 | 99.95084 | 43454 | 71454 | 66368 |
| | 3rd | 1.2760 | 148.9 | 116.7 | 99.88671 | 85153 | 165572 | 66735 |
| | 4th | 1.3030 | 382.4 | 293.5 | 99.70896 | 87020 | 425686 | 66787 |
| 1997 | 1st | 0.4631 | 83.6 | 180.6 | 99.93636 | 30813 | 92734 | 66536 |
| | 2nd | 0.3275 | 35.4 | 107.9 | 99.97310 | 22032 | 39633 | 67269 |
| | 3rd | 0.4337 | 42.9 | 98.9 | 99.96737 | 29316 | 48307 | 67593 |
| | 4th | 0.3070 | 62.2 | 202.5 | 99.95269 | 20723 | 69936 | 67506 |
| 1998 | 1st | 0.2230 | 22.1 | 98.9 | 99.98321 | 14981 | 24704 | 67193 |
| | 2nd | 0.3486 | 40.6 | 116.5 | 99.96910 | 23707 | 46012 | 68003 |
| | 3rd | 0.2317 | 24.1 | 103.9 | 99.98167 | 15794 | 27363 | 68169 |
| | 4th | 0.2955 | 41.0 | 138.9 | 99.96876 | 20044 | 46403 | 67828 |
| 1999 | 1st | 0.4116 | 38.4 | 93.2 | 99.97080 | 27880 | 43321 | 67737 |
| | 2nd | 0.1877 | 18.4 | 98.3 | 99.98596 | 12860 | 21059 | 68501 |
| | 3rd | 0.4163 | 91.3 | 219.2 | 99.93054 | 28572 | 104402 | 68635 |
| | 4th | 0.4018 | 49.4 | 122.8 | 99.96244 | 27379 | 56047 | 68142 |
| 2000 | 1st | 0.6061 | 68.7 | 113.4 | 99.94769 | 41421 | 78298 | 68343 |
| | 2nd | 0.4044 | 51.8 | 128.1 | 99.96058 | 27906 | 59572 | 68999 |
| | 3rd | 0.2572 | 24.0 | 93.5 | 99.98171 | 17876 | 27848 | 69507 |
| | 4th | 0.2879 | 27.5 | 95.6 | 99.97906 | 19941 | 31764 | 69261 |
| 2001 | 1st | 0.8301 | 105.8 | 127.5 | 99.91948 | 57635 | 122441 | 69434 |
| | 2nd | 0.3956 | 38.6 | 97.5 | 99.97065 | 27724 | 45050 | 70086 |
| | 3rd | 0.4087 | 44.2 | 108.0 | 99.96640 | 28943 | 52105 | 70809 |
| | 4th | 0.3515 | 30.4 | 86.4 | 99.97688 | 25074 | 36111 | 71325 |
| 2002 | 1st | 0.5928 | 70.4 | 118.8 | 99.94642 | 42534 | 84185 | 71748 |
| | 2nd | 0.6815 | 72.6 | 106.5 | 99.94478 | 49110 | 87144 | 72058 |
| | 3rd | 1.2102 | 102.8 | 84.9 | 99.92178 | 87805 | 124284 | 72555 |
| | 4th | 0.7040 | 98.0 | 139.2 | 99.92540 | 51339 | 119137 | 72924 |
| 2003 | 1st | 0.4798 | 40.8 | 85.0 | 99.96898 | 35138 | 49756 | 73242 |
| | 2nd | 0.2178 | 16.2 | 74.6 | 99.98764 | 15985 | 19863 | 73400 |
| | 3rd | | | | | | | |
| | 4th | | | | | | | |

1997 and later data excludes power supplier outages and major storms

SAIFI - System Average Interruption Frequency Index
SAIDI - System Average Interruption Duration Index (minutes)
CAIDI - Customer Average Interruption Duration Index (minutes per interrupted customer)
ASAI - Average Service Availability Index

Several design and planning guidelines have been established for this Long Range Plan to aid in achieving a reliable system design and provide further reductions in the number of outage hours per member. These guidelines are discussed in Section 4 – Planning Criteria, and Section 5 – Planning Approach.

# 3.0 Load Forecasts

## 3.1 General

The original forecasting approach envisioned for this project called for checking the 1999 NHEC load forecast against data for 2000 to 2002 to assess how that forecast has tracked actual loads. If that forecast were tracking growth closely, it could be used to support this study. A comparison of peak loads from the 1999 forecast with the sum of delivery point peaks used for this study is provided in Table 6-1.

**Table 3-1 1999 NHEC Load Forecast Vs Sum of Delivery Point Peaks**

| Year | Sum of DP Peaks | 1999 PRS | Difference |
|---|---|---|---|
| 1994 | 167,635 | 166263 | 0.8% |
| 1995 | 162,426 | 158576 | 2.4% |
| 1996 | 170,459 | 162043 | 5.2% |
| 1997 | 168,986 | 164715 | 2.6% |
| 1998 | 171,210 | 166712 | 2.7% |
| 1999 | 177,378 | 172372 | 2.9% |
| 2000 | 174,349 | 159567 | 9.3% |
| 2001 | 170,470 | 161698 | 5.4% |
| 2002 | 176,238 | 164297 | 7.3% |

Clearly, the historic peak data with DSM from the 1999 PRS are based on a different data series than is relevant for this study. The 1999 PRS non-coincident peak series is systematically lower than the sum of delivery point peaks. Based on this comparison and the rather substantial differences between the two series in the most recent years, it was determined that allocation of the 1999 NHEC forecast would not be an appropriate load forecast methodology. Rather, a bottom up approach which takes advantage of data now available at the delivery point and town level and the awareness of each district manager of growth trends in his district has been developed to support this study.

To support the NHEC long range system planning study, peak load forecasts have been developed for each of the 34 delivery points. A general methodology which separates load growth into number of consumers and demand per consumer has been used to develop the base forecast for each delivery point. We reviewed benchmark forecasts of these two components with district managers and made adjustments to reflect their knowledge of local trends, land use plans and specific development projects.

System planning efforts must recognize load concentrations at particular locations on the system that may require facility additions or upgrades. In recognition of this need, we had discussions with district managers to identify the locations of major existing loads that are part of the base forecasts for each delivery point. Finally, we identified expected new large loads which are in addition to the base forecast and located these to the extent possible.

This section develops the base forecasts and the large load forecasts for each delivery point in all districts. The discussion for each district includes a brief overview of the key growth trends and an evaluation of the data that are available to track system growth at the delivery point level. We present the two-factor base forecast for each delivery point and summarize the spot and incremental loads. This section is intended to document the development of load forecasts to the point of entry into the model of the distribution system.

## 3.2 Base Forecast Methodology

Small area forecasting to support system planning efforts typically reflects an effort to combine system level forecasts with location specific trends and developments. System level forecasts benefit more from sophisticated modeling efforts that can tie growth to demographic and economic indicators that are reported at the county level. Both the quantity and accuracy of the demographic and economic data and forecasts decline as smaller geographic areas are considered. Population data at the town level are available and useful for this type of study. The data analysis must be supplemented with local insight to get the needed location specific loads.

This study merges the system and small area forecasting approaches in the following way. The system study relates needed investments primarily to the maximum demands that are expected on key system components. Historic demand data are monitored for each delivery or metering point. Delivery point demands are equal, by definition, to the product of:

- The number of active consumer accounts
- The kW demand per active consumer

Active consumers can usefully be related to the population in the towns served by a delivery point. Fortunately, the consumer-population ratio (CPR) and the demand per consumer (DPC) tend to be rather stable factors over time and thus form a valuable basis for demand forecasting. For this study, the CPRs and DPCs for each delivery point have been established for 2002. Population forecasts have been developed based on the 1990 – 2001 trends for each town. The sum of the town population forecasts for all towns in each county have then been compared to the county population forecasts as published by Woods & Poole in 2002. Pro-rata adjustments have then been made to the forecast for each town to calibrate the town forecasts to the Woods & Poole county projections which reflect national and regional economic trends and age-cohort specific birth and mortality rates.

Benchmark forecasts for each delivery point were developed assuming that the CPRs and DPCs for 2002 remain constant through 2023 so that demand growth reflects the expected growth in the population served. These benchmark forecasts were then reviewed with each district manager and adjusted to reflect differential growth rates for the portions of the towns served by NHEC and for expected changes in DPCs. All final delivery point forecasts were approved both by district managers and by NHEC planning staff before the system modeling was initiated.

Exhibit I provides a large summary table that summarizes how the benchmark CPR and DPC forecasts were adjusted for each delivery point based on the discussions with NHEC District

Managers and staff. Section 6 then provides the tabular and graphic forecast summaries as the first section for each district. The Alton District forecast analysis is the first and most detailed to fully illustrate the analytic process that has been used for each district.

# 4.0 Planning Criteria

## 4.1 Overview

In order to provide consistency in the evaluation of delivery system requirements, we established specific performance standards for each level of the delivery system. As a general rule, the impact of an outage at the transmission level in terms of area, number of customers, and load affected is greater than at the distribution level; therefore, the planning criteria established for the various transmission system components are generally more stringent than for their distribution counterparts. The following sections discuss the planning criteria established for this study for purposes of defining system deficiencies and evaluating alternative plans.

## 4.2 Transmission & Subtransmission Design Criteria

### 4.2.1 Bulk Transmission System Design Criteria

The transmission business units of PSNH and Northeast Utilities follow these design criteria.

- **Voltage – 230 kV and greater:**
  - Normal: +/- 5% of nominal
  - Emergency: +/- 5% of nominal
  - Variation: not to exceed 10% of precontingency values
- **Voltage – less than 230 kV:**
  - Normal: +/- 5% of nominal
  - Emergency: + 5% to -10% of nominal
- **Power Factor:**
  - At interface between transmission and distribution system power factor shall be unity at the low voltage side of step-down transformer
- **Power Quality:**
  - Harmonics not to exceed limits of IEEE 519 Standard
  - Voltage flicker not to exceed limits of IEEE 141 Standard
  - Frequency variations are to be avoided
  - Voltage or power factor levels that could adversely affect electrical equipment are to be avoided

- **Transmission line and equipment loadings – System Normal or Generating Plant Loss:**
  - Load should be within normal ratings of equipment
- **Transmission line and equipment loadings – Emergencies:**
  - Load shall be within emergency ratings for non-radial contingencies for the loss of a single element
  - Load shall be within emergency ratings for non-radial contingencies for the simultaneous loss of two non-identical elements (i.e. generating unit and line, autotransformer and line, and generating unit and line)

### 4.2.2 Subtransmission (34.5 kV) Design Criteria

Subtransmission for NHEC is defined as those transmission facilities at 34.5 kV that emanate from various utilities and are used to serve the NHEC distribution system. The subtransmission analysis is based on the following design criteria.

- **Voltage – Regulated Load:**
  - Normal: 95% to 104.2% of nominal
  - Emergency: 92% of nominal
- **Voltage – Unregulated Load:**
  - Normal: 97.5% to 104.2% of nominal
  - Emergency: 95% of nominal
- **Power Factor:**
  - PSNH shall strive to maintain unity power factor at 34.5 kV line breakers at peak load conditions
  - 34.5 kV circuits shall be designed to maintain the following power factor ranges:

| Load Level (% of Peak) | Minimum Power Factor | Maximum Power Factor |
|---|---|---|
| 90-100% | .98 lag | 1.00 |
| 80-90% | .95 lag | 1.00 |
| up to 80% | .90 lag | 1.00 |

- **Equipment Loading – System Normal:**
  - Load should be within normal ratings of equipment

- **Equipment Loading – System Emergencies:**
  - Load shall be within emergency ratings of the equipment. Emergency ratings for transformers will be PSNH's TFRAT on the PSNH system and on NHEC's system will be the 65 degree rise over ambient temperature rating.
- **Design Philosophy (PSNH) – System Normal:**
  - No load loss will be permitted under normal summer or winter peak load conditions.
  - The system shall be capable of serving native PSNH load during peak load conditions without relying upon the faculties of customers or neighboring utilities unless in accordance with a specific contract.
- **Design Philosophy (PSNH) – System Emergencies (Contingent Operation):**
  - NHEC facilities except for radial 34.5 configurations, will be planned to a first contingency standard. NHEC will follow the outage and duration reliability design criteria of Section 4.4.
  - PSNH facilities – some losses of power to customers' loads will be accepted at time of peak load.
  - Load loss will not exceed 30 MVA and the duration of the load loss will not exceed 24 hours.
  - PSNH will perform up to three block load transfers as a means to reduce the loss of load exposure.[3]

## 4.3 Distribution Design Criteria

The planning criteria for the distribution system consists of three separate components:

- Voltage limits
- Thermal limits
- Contingency capability

### 4.3.1 Voltage Limits

This document establishes, among other things, voltage limits for distribution feeders based on the requirements of American National Standards Institute (ANSI) C84.1 1989 and RUS operating standards. These limits vary depending upon voltage class and are shown in the following table.

---

[3] This design criteria recognizes that most of PSNH transformers can be backed up by mobile transformers or faulted circuits can be repaired in less than twenty four hours unless under adverse conditions. (PSNH ED 3002 Distribution System Planning and Design Criteria Guidelines, 1/10/03)

**Table 4-1 Requirements[4] per ANSI C84.1 1989**

| Class of Service | Minimum Voltage | Maximum Voltage |
|---|---|---|
| Transmission Voltage | 107 | 132 |
| Distribution Voltage | 118 | 126 |
| Service Voltage | 114 | 126 |
| Customer Use Voltage | 110 | 125 |

Standards may also be established for the following service parameters and are based on ANSI and IEEE standards. These standards apply to:

1. Voltage Unbalance on Polyphase Service: For planning purposes the system should be designed such that the maximum voltage unbalance between individual phase conductors at the same location shall be less than or equal to 3%. This should be measured against the root mean squared (RMS) voltage of all phases at a location.
2. Voltage Flicker
3. Voltage Surges
4. Harmonics.

These additional standards are, for the most part, related to localized design dependent on specific loads being supplied. Consequently, they are not a major factor in developing this long range plan.

For this study we assume a distribution source voltage of 125 volts and allow 8 volts drop between regulation and one regulator beyond the distribution source. Voltage drops higher than those will require system improvements.

### 4.3.2 Electric Current Limits

*4.3.2.1 Underground Cable*

Thermal limits for underground primary distribution lines are defined in the operating guidelines of NHEC.

---

[4] Assumes a 120 volt base

Thermal ratings for some of the more common underground conductor sizes used for distribution feeders on the NHEC system when installed either as

1. Direct Buried,
2. Direct Buried in Conduit, or
3. Riser U-Guard

are shown in Table 4-2.

**Table 4-2 Summary of Distribution Feeder Underground Conductor Thermal Limits**

| Conductor | Current Rating | | 3θ Power Rating @ 12.5 kV | | 3θ Power Rating @ 24.9 kV | | 3θ Power Rating @ 34.5 kV | |
|---|---|---|---|---|---|---|---|---|
| | Normal | Emergency | Normal | Emergency | Normal | Emergency | Normal | Emergency |
| | (amps) | (amps) | (MVA) | (MVA) | (MVA) | (MVA) | (MVA) | (MVA) |
| **Direct Buried** | | | | | | | | |
| 1/0 AL | 259 | 290 | 5.6 | 6.3 | 11.2 | 12.5 | 15.5 | 17.3 |
| 500 AL | 510 | 570 | 11.0 | 12.3 | 22.0 | 24.5 | 30.5 | 34.1 |
| 500 CU | 630 | 700 | 13.6 | 15.1 | 27.2 | 30.1 | 37.6 | 41.8 |
| 750 AL | 625 | 695 | 13.5 | 15.0 | 26.9 | 16.6 | 37.3 | 41.5 |
| 750 AL-LC | 655 | 725 | 14.1 | 15.7 | 29.9 | 31.2 | 39.1 | 43.3 |
| **Single Conduit Direct Buried or Underground U-Guard** | | | | | | | | |
| 500 AL | 400 | 445 | 8.7 | 9.6 | 17.3 | 19.1 | 23.9 | 26.6 |
| 500 CU | 490 | 545 | 10.6 | 11.8 | 21.1 | 23.5 | 29.3 | 32.6 |
| 750 AL | 490 | 545 | 10.6 | 11.8 | 21.1 | 23.5 | 29.3 | 32.6 |
| 750 AL-LC | 520 | 575 | 11.2 | 12.4 | 22.4 | 24.7 | 31.1 | 34.4 |

***The data in** Table 4-2 **is provided for illustrative purposes only. For specific applications, the reader should refer to NHEC's operating guidelines.***

In general, the maximum current carrying capacity is determined by cable operating temperature limits for both normal conditions and emergency conditions. The operating temperature is defined as the limiting temperature the cable is allowed to reach under normal conditions. The cable may operate at this temperature indefinitely. The emergency temperature is defined as the temperature the cable is allowed to maintain for not more than a 36 hour period, of which there may not be more than three incidences in twelve consecutive months. The approved cable temperature limits are 90°C for system normal conditions and 110°C for system emergency conditions.

Parameters such as duct bank size and material, cable position, soil conditions, and load factors are recognized in the calculation. Refer to NHEC's guidelines for further information.

### *4.3.2.2 Overhead Lines*

Thermal ratings for some of the more common overhead conductor sizes used for distribution feeders on the NHEC system are shown on Table 4-3.

**Table 4-3 Summary of Distribution Feeder Overhead Conductor Thermal Limits**

| Conductor | Current Rating | | 3Ø Power Rating @ 12.5 kV | | 3Ø Power Rating @ 24.9 kV | | 3Ø Power Rating @ 34.5 kV | |
|---|---|---|---|---|---|---|---|---|
| | Summer $104^{o}$F Amb. | Winter $32^{o}$F Amb | Summer $104^{o}$F Amb | Winter $32^{o}$F Amb | Summer $104^{o}$F Amb. | Winter $32^{o}$F Amb | Summer $104^{o}$F Amb. | Winter $32^{o}$F Amb |
| | (amps) | (amps) | (MVA) | (MVA) | (MVA) | (MVA) | (MVA) | (MVA) |
| 4/0 CU | 525 | 680 | 11.3 | 14.2 | 22.6 | 29.4 | 31.4 | 40.6 |
| 350 MCM CU | 720 | 940 | 15.6 | 20.3 | 31.0 | 40.6 | 43.0 | 56.2 |
| 336 MCM AL | 560 | 730 | 12.1 | 15.8 | 24.2 | 31.4 | 33.5 | 43.6 |
| 556 MCM AL | 750 | 990 | 16.2 | 21.4 | 32.3 | 42.8 | 44.8 | 59.2 |
| 4/0 ACSR | 395 | 510 | 8.5 | 11.0 | 17.0 | 22.0 | 23.6 | 30.5 |
| 336 MCM ACSR | 560 | 730 | 12.1 | 15.8 | 24.2 | 31.4 | 33.5 | 43.6 |
| 477 MCM ACSR | 705 | 920 | 15.2 | 19.9 | 30.5 | 39.7 | 42.1 | 55.0 |

***The data in** Table 4-3 **ie provided for illustrative purposes only. For specific applications, the reader should refer to NHEC's operating guidelines.***

The Cooperative also uses overhead covered wire to reduce the number of tree outages contact. Table 4-4 reflects the ratings of the more commonly used conductors.

**Table 4-4 Distribution Feeder Covered Overhead Conductor Thermal Limits**

| Conductor | Current Rating | | 3Ø Power Rating @ 12.5 kV | | 3Ø Power Rating @ 24.9 kV | |
|---|---|---|---|---|---|---|
| | Normal | Emergency | Normal | Emergency | Normal | Emergency |
| | (amps) | (amps) | (kW) | (kW) | (kW) | (kW) |
| **SUMMER** | | | | | | |
| 1/0 | 205 | 256 | 4,400 | 5,500 | 8,500 | 10,600 |
| 336 ACSR | 418 | 522 | 9,000 | 11,300 | 17,300 | 21,600 |
| **WINTER** | | | | | | |
| 1/0 | 271 | 339 | 5,900 | 7,300 | 11,300 | 14,100 |
| 336 ACSR | 551 | 689 | 9,000 | 11900 | 22,800 | 28,500 |

For this study we assume conductor loading no greater than the following:

1. For all single phase taps no more than 50 amps
2. For three phase and major ties, no more than 50% of the emergency rating of the conductor as shown above, or 280 amps, which ever is smaller.

*4.3.2.3 Distribution Substation Transformers*

The charts in Exhibit II utilize the ANSI standard to produce a transformer capability guide assuming a 70% and 100% preloading cycle on the substation transformer. Based on the ANSI/IEEE C59.92 – Substation Transformer Loading guides, this study recommends distribution substation equipment improvements when the following load levels are reached.

| Equipment | Summer | Winter |
|---|---|---|
| Transformers | 90% | 110% |
| Regulators | 100% | 100% |

### 4.3.3 Contingency Capability

Distribution feeders and substations are designed as part of radial systems, so the failure of critical equipment will cause customer outages. In general, NHEC has adopted a standard which provides substation to substation feeder level loops that are designed to be operated normally open. In general, the loading on each feeder in the loop is limited to 50% or less of the thermal emergency rating of the conductors so that a single feeder could provide complete backup to allow restoration of mainline capacity and restoration of service to most customers with simple manual field switching. This switching generally occurs within approximately one hour under single-contingency conditions. However, there are areas within the NHEC service area, (generally in the more sparsely populated portions of the system), where it is not economically feasible to meet this criterion.

It is a reasonable and customary practice of NHEC to prepare and document contingency switching orders to return a feeder or substation to service after an outage. These contingency switching orders recognize the localized and time varying nature of the distribution system loads and the local capacity limitations of the serving system. The orders are developed in joint co-operation with the NHEC engineering group and the NHEC operations group.

Some locations also may have equipment provided with customer funding to provide automatic switching between two or more sources, resulting in automatic restoration of service for single contingency service interruption after durations of several seconds or less.

## 4.4 Reliability

Reliability was reviewed on the basis of the outage rates of the various facilities. Deficiencies are defined to exist where the average outage rate during the past three years is more than 150 percent of the expected value for these facilities. The expected value is based on the performance of the 10th percentile facility (i.e., 90 percent of the facilities of similar type and purpose have a lower outage rate).

Expected outage rates are as follows:

| | |
|---|---|
| 115 kV and above transmission and substations: | 1.5 outage/year |
| 34.5/69 kV transmission and substations - *network*, or | 4 outages/year |
| *radial* configuration | 2 outages/year |
| Main-line distribution feeder: | 2 outages/year |
| Large capacity distribution feeder tap: | 2 outages/year |
| Distribution feeder tap: | 1 outage/year |

In general, the RUS reliability guidelines require that there be no more than an average of 5 customers hours of outage per year in rural areas, 3 customer hours of outage per year for consumers in suburban areas and 2 customer hours of outage per year in urban areas. Outages caused by major storms or by the power suppliers may be excluded. Calculations should be based on the last 5 consecutive years in any specific area. In addition, no single sectionalizing device should be out of service more than twice during any six-month period.

# 5.0 Planning Approach

## 5.1 General

For convenience, the report discussion of the Long Range Plan is organized by district in Sections 6.0 – 15.0. Each section discusses the recommended distribution system projects in the 2004-2023 Long Range Plan, with the recommendations divided into the following planning periods:

- 2004-2008
- 2009-2013
- 2014-2023

The distribution system recommendations along with alternatives are organized in the following manner:

- New substations, delivery points (DP) and meter points (MP);
- Existing substation, DP and MP changes;
- Existing system review
- Recommended distribution primary line improvements by substation, DP and MP
- Cost Estimates.

The proposed plan indicates substation, DP, MP and primary distribution system improvements that are anticipated to be necessary to provide the required capacity, voltage and the service reliability levels.

The proposed construction projects are identified by project item numbers. These project numbers are shown on the Proposed System Circuit Diagram for each district and in the cost tables in the text. The unit costs used to develop the total cost of each recommendation and alternative are contained in Appendix C - Unit Cost Estimates. The projects and item numbers shown in GREEN are anticipated in the 2004-2008 Transition Plan time period. Projects and item numbers shown in BLUE are projected to be needed in the 2009-2013 Transition Plan, while projects and item numbers shown in RED are in the remaining 2014-2023 time period. Projects and item numbers shown in ORANGE are potential reliability improvement projects.

## 5.2 System Modeling

### 5.2.1 Transmission & Subtransmission Modeling

PSNH, NHEC and PSE staffs participated in a joint transmission planning effort. First steps included developing a joint planning approach, exchange of planning criteria, an exchange of reliability reporting information, and an exchange of existing power flow analyses. Subsequently, three distinct joint planning sessions were undertaken to test the existing system with NHEC predicted future load levels.

The transmission and subtransmission system study used the Power System Simulation/Engineering power flow computer program package by Power Technologies Incorporated. The transmission system model included the PSNH transmission model representing the 69 kV through 345 kV AC and 450 kV DC voltages combined with the PSNH 34.5 kV subtransmission system model. We developed two base cases to correspond with summer and winter coincident peak system loading conditions since the PSNH is forecasted to be largely summer peaking while the NHEC system is forecasted to remain winter peaking.

We used the existing system model of the 34.5 kV PSNH subtransmission system and Northeast transmission system to examine the existing system conditions for the 2002-03 winter system peak and the 2003 summer peak. Loads for the winter peak were based upon PSNH's telemetered coincident peak load data from their System Dispatch Center. The 2003 summer peak model used the 2002 summer coincident peak loads modified by the projected growth rates for the local areas.

The forecasted load growth for the 20 year planning horizon was applied to the existing system model to test the ability of the system to meet performance and design criteria. Deficiencies, or system conditions which are outside of the design criteria established for planning purposes, are then identified and solutions to solve these deficiencies in a least cost manner are then tested, compared and incorporated in the plan. Because the load forecast was developed on a non-coincident peak basis and the model requires coincident system loads, the equivalent non-coincident growth rates for summer and winter season peak loads were applied to the base case 2002 winter peak and 2003 summer peak load models to arrive at the proper coincident load levels to test the system performance. For uniformity and to stress the system, the highest average annual growth rate for an NHEC and PSNH model area was applied to the entire PSNH model for that respective portion of the system.

To facilitate an orderly planning process a three step approach was used. In the first step, PSNH subtransmssion design criteria were utilized to test the system and determine deficiencies and solutions. In the second step, a more stringent first contingency design criteria was applied and the system performance tested, deficiencies noted, and solutions determined. In the third step, reliability improvement in those areas where marginal system performance was identified or where major system reinforcements were needed in step two analysis were utilized with a variety of reliability improvement options to refine the network design. This three step approach addresses capacity, contingency, and reliability design and planning requirements in a comprehensive manner.

### 5.2.2 Distribution Modeling

NHEC maintains a computer model of the primary distribution system of each substation, DP and MP using Milsoft Integrated Solutions, Inc., WindMil software program. The computer model consists of two parts:

- The primary distribution system and configuration (line sections, conductor sizes, phasing, switches, voltage regulators, capacitors, step-down transformers and overcurrent protection equipment),
- Load by line section and phase developed from actual billing data.

NHEC provided an up-to-date copy of the computer model that represented the existing primary distribution system configuration and load level. The individual substation, delivery point (DP) and meter point (MP) models were combined to create district computer models. The load level of each substation, DP and MP was adjusted to represent the 2003 base load level to be used by the Long Range Plan. Then, load models for the years 2008, 2013 and 2023 were developed by taking the district load forecast and allocating the anticipated new load to the substations, DP's and MP's within each district.

WindMil was then used to calculate the voltage drop and load for each line section throughout each district. The corresponding circuit load for each substation, DP and MP is shown by district in Sections 6-15.

The existing system configuration was reviewed using the 2023 load level to identify areas where voltage and capacity improvements are needed. The system was then analyzed to determine the appropriate alternatives and the recommended system improvement for each problem area. The improvements were prioritized and assigned to one of the three Transition Plan time periods. The recommended plan is discussed by district in Sections 6 - 15.

The calculated voltage drop before and after the recommended improvements and the distance from the supplying substation, DP or MP for the proposed Long Range Plan is shown on the Proposed System Circuit Diagram for each district. Changes in opens, circuit boundaries and line regulator placement that are associated with the recommended line construction projects are also shown on the Proposed System Circuit Diagrams.

## 5.3 Alternate Solutions

### 5.3.1 Traditional Solutions

Distribution system problem areas relating to voltage and capacity that were found during the review of the existing system configuration using the 2023 load level were studied to determine the recommended system improvement. The traditional solutions that were considered during the development of the recommended plan include the following:

- Addition of new substations, DPs and MPs;

- Upgrades of existing substation, DP and MP capacity;
- The addition of new circuits from existing substations and DPs;
- Conversion of small conductor three-phase lines to large conductor three-phase lines;
- Conversion of single-phase lines to three-phase;
- Construction of tie lines enabling load transfers to other lines;
- Conversion of voltage from 7.2/12.5 kV to 14.4/24.9 kV or 19.9/34.5 kV; and/or
- Addition of capacitors and voltage regulators.

### 5.3.2 Distribution Automation

The availability of Distribution Automation System (DAS) and traditional Supervisory Control and Data Acquisition (SCADA) capability was recognized in the planning process in three ways:

- The planning process considered the increasing demands placed on system design due to the availability of DAS/SCADA to enhance system performance and reliability, coupled with increased customer expectations regarding service quality;
- Data developed from monitoring the operations of the delivery system with DAS/SCADA was utilized to enhance planning accuracy; and
- DAS/SCADA itself was recognized, in certain instances, as an alternative to more traditional approaches to increasing delivery system capacity.

The current planning effort takes into account the enhanced operational capability brought about by an expanded DAS/SCADA system. For example, automated field switching, in some instances, can provide a more cost effective alternative to additional substation transformer capacity, to deal with a first contingency outage caused by a substation transformer failure. Some of the ways DAS/SCADA may be used as an alternative to other construction options are:

- To improve system performance
  - Control vars;
  - Control voltage;
  - Push temperature limits; and
  - Optimize system configuration for minimal losses.
- To meet contingency situations
  - Load transfer;
  - Spot generation;
  - Load reduction (i.e., load management, interruptibles, price signaling); and
  - Faster response to contingencies.

- To meet normal load requirements
  - Operate closer to limits for voltage and capacity;
  - Load reduction; and
  - Spot generation.

### 5.3.3 Distributed Generation

*5.3.3.1 Value of DG from a T&D Construction Deferral Perspective*

Historically, utilities have generated electricity centrally and used a large, sophisticated transmission and distribution (T&D) system to deliver the energy to customer. The capacity of the generation, transmission, and distribution systems become constrained once the demand increases beyond a certain level. Once this occurs, the traditional utility generates more electricity, and builds new T&D facilities to allow the additional energy to be delivered to the end-user. An alternative to this traditional approach that may allow deferral, or even elimination, of T&D additions or upgrades is to invest in distributed generation (DG) to satisfy demand locally and incrementally.

The planning method used throughout this study is peak capacity planning. Peak capacity planning is the evaluation of the ability of the system to carry the projected peak system load. To determine the duration of the projected peak load, historical loading information has been used to create location specific load duration curves. These load duration curves are used as a tool to indicate the amount of time that the load on a certain portion of the system is above its peak demand in any given year. These load duration curves are then used to help determine the amount of hours in a given year that the demand on a given portion of the system exceeds the capabilities of the existing T&D infrastructure. The bad duration curves also show the amount of capacity in excess of the utility system design limits. These two quantities help to determine how much DG could be used for reducing the peak demand and how many hours of operation will be needed to compare to the traditional T&D investment option.

*5.3.3.2 Value of DG from a Demand Uncertainty Perspective*

Prior to committing to any high-cost, long lead-time utility investment, an evaluation of demand uncertainty is needed. These investments may actually take longer and cost more than originally projected, therefore making other alternatives more feasible. For example, the load growth may not be developing as originally projected, therefore making the high-cost investment turn into a stranded investment, possibly making DG a more feasible alternative.

Generally, DG may provide a realistic alternative to traditional T&D investment in areas of low to modest growth rates. Historically, utilities have "overbuilt" low growth areas of the system causing the transmission and distribution system to contain unused system capacity immediately after the construction investment is made. As a remedy, modular DG can be installed to meet the incremental demand and defer the large investment until it is needed, if at all.

In high growth areas, the cost effectiveness of adding modular DG to defer a T&D investment becomes unrealistic since it only defers the T&D investment for a few years. In these cases, it is more economical to invest in the higher cost T&D construction alternative. This construction may still create unused capacity in the T&D system, but for a smaller period of time.

For the purpose of the DG evaluation in this study, all areas served by New Hampshire REC were assumed to be in the low to moderate growth category, therefore allowing all areas to be screened for DG potential.

*5.3.3.3 Value of DG from a Power Supply Perspective*

The focus of this study is on the development of a Long Range Plan for the expansion and enhancement of the transmission and distribution (T&D) system. Distributed generation (DG) is simply one of the alternatives available to NHEC to accomplish these objectives. However, DG also has the potential of enabling the cooperative to reduce its power supply cost by reducing billing demand or producing generating capacity credits; and the potential value of this should be recognized in the economic evaluation of the alternatives.

Until the late 1990s, establishing the potential impact of DG in reducing NHEC's power supply costs was relatively straightforward. Simply put, NHEC was under a requirements type contract[5] that prohibited the Cooperative from utilizing DG to reduce its purchase power cost. If this contractual hurdle could have been overcome (for example, by having a retail consumer own the DG), the value of DG would have been equal to any reduction that could have been achieved in billing demand multiplied by the wholesale demand charge. In the case of PSNH, this would have been $10.00/kVA/mo. In certain instances, the value might have been extended beyond the months in which the DG was operated due to impact of a ratchet clause in the wholesale tariff.

The advent of retail competition in New Hampshire, however, changed all that and complicated the determination of the value of DG from a power supply perspective. In the early days of retail competition in New Hampshire, utilities wishing to continue in the distribution delivery service business were prohibited by law and/or Commission regulations from selling power and energy at retail, except for transition service during a limited time period and as a supplier of last resort. NHEC, however, was able to get legislation passed that recognized that a cooperative was different than an investor owned utility (IOU), by allowing NHEC to function as an aggregator for its member-consumers, purchasing power and energy on their behalf and offering it as a continuing retail option. While NHEC's members were not required to purchase their power and energy from the cooperative and maintain the right to purchase from other alternative suppliers, to date all of the members have chosen to continue purchasing from the cooperative. Thus, NHEC's purchase power arrangements continue to be relevant in establishing the value of DG from a power supply perspective.

[5] The term "requirements" power refers to a contractual form of supplying power and energy wherein the supplier commits to supplying whatever the customer might need.

In the area formerly served by PSNH, the cooperative has gone out for competitive bids to cover its power supply requirements.[6] At the present time, NHEC has a contract with Duke Energy Trading & Marketing to deliver most of its power and energy requirements in the PSNH area on a requirements basis through December 31, 2006. The rate for this purchase will average approximately 46 mills/kWh over the life of the contract. The rate structure for this purchase consists of monthly on-peak and off-peak energy charges, with the capacity and bulk transmission component rolled into the energy charge. In addition, the cooperative pays the New England Power Pool (NEPOOL) approximately $1.15/kW/mo. for regional network transmission service, plus $0.19/kW/mo. to Northeast Utilities (NU) for local network transmission service, plus $0.98/kW/mo. for PSNH subtransmission and delivery point service.

Under the current arrangement, because the wholesale rate structure does not include an identifiable demand charge component there is no immediate value in using DG to reduce billing demand. While there is some impact on the energy side, the reduction in purchased energy costs is most likely more than offset by the fuel cost associated with operating the DG unit so there is a net negative value, albeit relatively small assuming that the DG is operated a relatively few hours during the year. Thus, on a short term basis, DG would appear to have minimal impact on purchased power costs.

The long term value of DG in reducing purchased power cost, however, is more complicated and subject to debate. One way of looking at the situation is that even under a rate structure that includes only an energy charge, capacity costs are still being recovered; and any improvement in annual or seasonal load factor will ultimately be reflected in lower prices. Furthermore, the Federal Energy Regulatory Commission (FERC) is encouraging the establishment of a capacity market, separate and distinct from the energy market.[7] In fact, such a capacity market has already been established in New England. As of March 1, 2000, the New England energy market provides location-based pricing; and FERC has ordered New England to make pricing in the capacity market location-based late in 2004. These mechanisms should provide the necessary structure to allow the markets to value the capacity and energy provided by DG. However, in either case, the value of DG capacity is not likely to be well defined or predictable very far into the future with any degree of accuracy. Currently, the Unforced Capacity (UCAP) product has been priced at something in the range of $0.30 to $0.50/kW/mo. in the advance auction and zero in the after-the fact deficiency auction due to a significant amount of merchant generation coming on line and more than adequate capacity installed for the present. However, the situation is dynamic, with some of those merchants who bought divested generation from investor-owned utilities (IOU) at prices that were apparently too high for them to recover their costs. An example of this is NRG, who purchased such generation at a multiple of book value, and has recently filed for protection under Chapter 11 of the bankruptcy laws.

---

[6] NHEC currently has seven distinct wholesale power supply arrangements to serve its retail load through geographically separate interconnections with four different transmission providers -- Public Service Company of New Hampshire (PSNH), Central Vermont Public Service Company (CVPS), Green Mountain Power Corporation (GMP) and New England Power Company (NE). However, the delivery points in the PSNH area account for roughly 96 percent of the cooperative's total load; therefore, the discussion of the value of DG in terms of reducing power supply costs focuses primarily on power supply arrangements for the PSNH area.

[7] FERC has recently issued a Notice of Proposed Rule Making (NOPR), entitled Standard Market Design (SMD) and Structure, issued November 26, 2002.

On a theoretical basis, it seems reasonable to assume that the long term value placed on capacity by the market should approximate the merchant owned combustion turbine (CT), since a CT represents the lowest cost option for supplying new capacity.[8] A cost estimate based on this assumption is provided below.

**Table 5-1 DG Cost Estimate**

| | | |
|---|---|---|
| 1. Estimated installed cost | | $500/kW |
| 2. Annual fixed costs | % | |
| a. Capital recovery (10.5%, 30 years) | 11.1 | |
| b. Property taxes and insurance | 2.0 | |
| c. Income taxes (0.40 x 0.50 x 0.15) | 3.0 | |
| d. Fixed O&M | 1.0 | |
| e. Subtotal | 17.1 | |
| f. Annual fixed costs | | $85.50/kW/year |
| g. Equivalent monthly cost | | $7.13/kW/year |

On the other hand, some would argue that the long term market place value will tend to be less than the cost of a merchant owned CT since there will be a tendency of the industry to have excess capacity, rather than be capacity deficient; and this will tend to drive market prices down. While for several years there was a tremendous push in some areas, including New Hampshire, to move to a competitive market away from a regulated industry structure, problems in California and elsewhere, at the least, slowed down the transition, and possibly stopped it altogether. Consequently, the power supply function in the United States exists in a dual world of regulation and competitive market. Thus, the principles that one might expect a competitive market to follow are not fully evident at the present time. Many utilities continue to have responsibility for serving all of the load in their assigned service areas, and tend to plan on a conservative basis, leading to a preponderance of years having excess capacity compared to years having deficient capacity.[9] Many potential merchant suppliers have, in fact, complained

[8] A "merchant" owned plant refers to a plant that is owned by a non-utility entity that has entered the market for the sole purpose of realizing a profit. The reason that this distinguishing characteristic is important is that it is likely that an owner in this situation will demand a higher return on equity ("ROE") than would be the case for a regulated utility. The weighted cost of capital for a merchant owned plant is estimated as follows:

| | | | | | |
|---|---|---|---|---|---|
| Debt | 50% | @ | 6.0% | = | 3.0 |
| Equity | 50% | @ | 15.0% | = | 7.5 |
| | | | | | 10.5% |

[9] In New England, many utilities operating under commission orders, have divested themselves of their generation. However, they generally remain responsible for providing transition and/or default service, but are forced to procure it competitively from wholesale marketers who either purchased the utilities' generating assets or purchase power and energy from merchant generators who purchased such assets and/or are building new ones. PSNH is a slight exception in that while it was originally ordered to sell its assets, and did sell their nuclear assets, a law was passed

that this tendency has increased their risk and decreased their profit potentials to the point that they are unwilling to enter the market with new capacity. Thus, it is our conclusion that the value of DG from a power supply perspective is most likely to be somewhat less than the full cost of a merchant owned CT, but greater than zero as the current purchased power arrangement might appear to indicate.

Another potential value of DG is in reducing bulk power transmission charges. Since bulk power transmission charges are typically billed on a load ratio for $/kW/mo. basis, one might be tempted to conclude that using DG to reduce the monthly coincidental peak demand of the transmission system would result in a corresponding reduction in transmission charges. However, FERC has made it very clear that "behind the meter" generation, such as DG, may not be used to reduce transmission obligations and charges.[10] FERC's rationale is that such generation will, at some point in time, be out of service; and the transmission system must be designed to handle this contingency. Thus, FERC argues, there should be no recognition of "behind the meter generation" in reducing transmission requirements. While the application and enforcement of this policy is admittedly spotty across the country, we do not believe that NHEC should plan on the basis of realizing a reduction in transmission costs through DG.

In summary, it seems clear that the immediate potential value of DG in reducing power supply cost is zero, because NHEC currently purchases the bulk of its requirements under a wholesale rate that does not include a specific demand charge component. Over the long term, using DG to improve the cooperative's annual or seasonal load factors should be of some value, although the exact value to be placed on this is open to speculation. On the high side, the long term steady state value should be no greater than the cost to install a merchant owned CT. However, the actual value may be significantly less than that amount. For purposes of this report, after consultation with NHEC's staff and power supply consultant, we have elected to place a power supply value on DG of $2.25/kW/mo. in the economic evaluations of DG alternatives. This includes approximately $0.98/kW/mo. and $0.19/kW/mo. in subtransmission service charges from PSNH and NU, respectively.

### 5.3.4 Reliability Analysis

*5.3.4.1 General*

Electric utilities are expected to provide continuous and quality electrical service to their customers at a reasonable rate by making economical use of available system and apparatus. Continuous electric service has come to mean meeting customer's electric energy requirements as demanded consistent with the safety of the employee, customer, public and system equipment. Quality electrical service involves meeting customers demands within specific voltage, frequency, disturbance and reliability limits. Reliability limits as perceived by the consumer are

---

mandating PSNH retain its fossil and hydro-electric generating units in an attempt to assure less volatile and lower transmission prices.

[10] "Behind the meter" generation refers to generation that is located on the load side of the wholesale meter.

characterized by the number of outages experienced in a given period of time and the time duration of those outages.

To maintain reliable service a utility must have adequate redundancy in its system to minimize the number of customers affected by a component outage and also minimize the duration of an outage by facilitating the restoration of service by transfers of outaged but unfaulted systems to available alternate supply paths. In the absence of alternate supply paths and sectionalizing, the only operating option available to the utility to enhance reliability is to minimize the duration of the outage by the rapid repair of failed equipment.

Utility experience indicates that most transmission and distribution service interruptions are the result of damage from natural elements, such as lightning, wind, rain, snow, ice and animals. Other causes include defective materials, improper installation, equipment failure, excavation dig-ins, vandalism, tree pruning, vehicle accidents and other accidental contacts. By far the largest and most damaging reliability event occurs with major storms where lightning and wind or ice, snow and wind can cause widespread outages and extensive equipment damage. Restoring service after a major storm event relies upon having a sufficient number of crews, mobile and mechanized equipment, and construction supplies.

From an operating perspective, preventive maintenance when coupled with outage reporting systems which identify outage root causes can be most effective. From a system design perspective, systems planned and designed to a specific contingency level, such as first contingency for the distribution system and first or second level contingency in the transmission system, can significantly influence outage durations. A system designed on a contingency level ensures that an alternate supply path is available thereby enabling operators to restore outaged consumers to service more rapidly. Contingency analysis in the system planning activity helps determine weaknesses in the supply system which need to be addressed to maintain reliable service by minimizing outage durations.

### *5.3.4.2 Reliability Improvement Methods*

Consumers assess their electric service reliability on those factors that they can observe, namely the outage, the duration of the outage and the number of outages experienced in a given period of time. Utilities assess electric reliability in industry standard terms such as the following reliability indices[11]:

**Average service availability index (ASAI)** – the fraction of time (often in percentage) that a customer has power provided during one year or the defined reporting period. In words, ASAI is equal to:

$$\frac{\textit{Customer Hours Service Availability}}{\textit{Customer Hours Service Demand}}$$

[11] IEEE (draft standard) P1366 Trial Use Guide for Electric Power Distribution Reliability Indices

**Customer average interruption duration index (CAIDI)** – the average time required to restore service to the average customer per sustained interruption. In words, CAIDI is equal to:

$$\frac{\Sigma\ \textit{Customer Interruption Durations}}{\textit{Total Number of Customer Interruptions}}$$

**System average interruption duration index (SAIDI)** – designed to provide information about the average time the customers are interrupted. In words, SAIDI is equal to:

$$\frac{\Sigma\ \textit{Customer Interruption Durations}}{\textit{Total Number of Customers Served}}$$

**System average interruption frequency index (SAIFI)** – designed to give information about the average frequency of sustained interruptions per customer over a predefined area. In words, SAIFI is equal to:

$$\frac{\textit{Total number of Customer Interruptions}}{\textit{Total Number of Customers Served}}$$

These indices generally measure total system reliability performance but have also been applied at the bulk power supply point and individual substation, feeder, and in some cases sectionalizing device level.

All of these indices and the consumer's perception of service reliability involve number of outages, duration of the outage(s), and customers affected by an outage. Therefore, if the utility can minimize any of these parameters by operating, construction, design or planning practices, reliability will be improved.

On the following page Table 5-1 lists a variety of methods and designs which can be used to improve service reliability, along with the affected reliability index.

**Table 5-1 Options for Improving Service Reliability**

| | **Number of Outages** (Improvements to SAIFI) | **Number of Consumers Impacted** (Improvements to CAIDI) | **Minimization of Outage Duration** (Improvements to SAIDI) |
|---|---|---|---|
| **Maintenance practices coupled with advanced outage reporting** | | | |
| Adequate forestry practices | x | | |
| Adequate grounding, shielding and lightning arrestor application | x | | |
| Animal guards on terminal equipment | x | | |
| Periodic in-service equipment inspection | x | | |
| **Construction practices** | | | |
| Use of tree wire where appropriate | x | | |
| Use of private right-of-way instead of road right-of-way | x | | |
| Line equipment purchase quality assurance practices | x | | |
| Personnel equipment, installation and operation training | x | | |
| Preventive maintenance testing – Doble and Transformer Testing | x | | |
| Exposure minimization | x | | |
| **Protection and Control** | | | |
| Coordinated sectionalizing | x | x | x |
| Localize and isolate outage to smallest reasonable area | x | x | x |
| Utilize auto-sectionalizers to isolate and bifurcate network | x | x | x |
| Utilize auto-sectionalizing on radial looped feeders | x | x | x |
| Utilize SCADA and DMS for remote switching and network reconfiguration | x | x | x |
| Utilize reclosers which operate single phase in place of the conventional three phase operation devices. | x | x | x |
| Utilize fault location tools, fault indicators, relays | | | x |
| Fuse all radial taps off of the main line | x | x | x |
| Limit number of customers per feeder and sectionalizing device | | x | x |
| Convert networked feeders to open loop configuration | | x | x |
| Increase remote control and indication | | | x |
| Increase use automatic line sectionalizing | | | x |
| **Design Practices** | | | |
| Consider primary or secondary spot networks | x | x | |
| Consider low voltage network service | x | x | |
| Consider dual feeder preferred and emergency source transfers | x | x | |
| Consider distributed generation for backup | x | x | x |
| Consider substation designs which incorporate faulted equipment isolation without loss of load | x | x | |
| Design system to first contingency standards to facilitate timely load transfer switching | | | x |

### *5.3.4.3 Examples of Quantification of Major Reliability Improvement Measures*

Conversion of a Networked Feeder to a Looped Configuration

The PSNH 34.5 kV distribution feeder system is operated in three different configuration modes: radial, looped and network. PSNH has operated the Laconia-Webster 34.5 kV feeders in a network configuration. If a permanent fault developed on a networked feeder, the feeder breakers at Laconia and at Webster open with the result that the entire feeder from Laconia to Webster is de-energized.

If we assume for discussion purposes that PSNH will open the Webster-Laconia feeder at its midpoint, then for a customer that was served from this network:

- The line miles of exposure to outages is cut in half with the result that this line section will be exposed to one-half of the outages it would be in a networked configuration.
- The number of customers outaged by a single outage event will also be halved from the networked configuration.

The overall improvement in reliability provided by this networked to looped reconfiguration is twice for the utility whose load is not split equally with half served by Laconia and the other half served by Webster. The reliability improvement is a factor of four times better for the utility whose load is also split equally between the Webster and Laconia sources.

Adding a New Distribution Substation to the Network

PSNH plans to build an entirely new 115 – 34.5 kV substation at Brentwood. Brentwood substation will serve an area formerly supplied by Madbury and Chester substations.

Assuming this new substation is positioned midway between Madbury and Chester, and feeders will be extended to normally open points midway between these substations, the resultant feeder lengths and thus exposure to outages will be cut in half and therefore reliability will be improved by a 2x factor. If the utility impacted also has its load bifurcated, the reliability will improve by a four times factor.

### 5.3.5 Reliability Planning Approach

The historical distribution system reliability indices were calculated for each feeder and district in the NHEC system by using an individual outage detailed database for years 2000-2002. Outage types that were excluded from the distribution reliability analysis were:

- Outages affecting less than 5 members
- Outages lasting less than 5 minutes ("momentary" outages)
- Power Supplier Caused Outages
- Outages that occurred on 34.5 kV lines owned by NHEC
- Major Storms

Each feeder was classified as being generally rural, suburban, or urban in nature. Circuit configuration, length, service area density, number and type of members, NHEC staff input, as well as information from the 2000 U.S. Census Bureau Urban Area Maps via the World Wide Web were all considered in the classification process. The feeder classifications were then compared to the corresponding index design criteria as listed below.

**Table 5-2 Distribution System Reliability Criteria**

| | SAIFI | SAIDI |
|---|---|---|
| Urban | 2.0 | 2.0 |
| Suburban | 2.0 | 3.0 |
| Rural | 2.0 | 5.0 |

The SAIFI of 2.0 for all feeder classifications indicates that, on average, no member should be exposed to more than two outages per year. The SAIDI index criterion indicates that rural members are allowed to experience a higher duration of outage-hours due to more miles of primary line exposure. On the other hand, urban members should receive a higher level of reliability due to shorter circuits, more members per mile, and underground feeder configurations.

Any feeders that exceeded the criteria were reviewed. A root cause analysis was completed to determine if there were any potential O&M solutions such as tree trimming, animal guard installations, underground conductor replacement, etc. that would significantly improve future reliability. In addition, these feeders were reviewed for potential capital investment projects, such as new substations, feeders, or tie-lines, that would provide potential reliability improvement.

There were also recognized projects that pertained to feeders that met the reliability criteria over the three-year sample period during 2000-2002. Even with the higher levels of reliability, the proposed projects were mentioned as possibilities to improve reliability through increased backup capabilities, phase balancing potential, and new feeder configuration alternatives.

## 5.4 Substation Transformer Replacement

NHEC requested recommendations for substation transformer replacement due to age and obsolescence. We reviewed the cooperative's test reports and found most units operating very well. Maintenance issues such as high moisture, small oil leaks, rust and high combustible gas are usually repairable at modest cost. For planning purposes, we recommend replacement when a unit is 50 years old, unless maintenance issues suggest an earlier replacement. There may be situations where a longer lifetime is possible, which can be determined on a case-by-case basis when the 50 year mark occurs.

# District Sections

# District Sections - Table of Contents

# List of Tables

# List of Figures